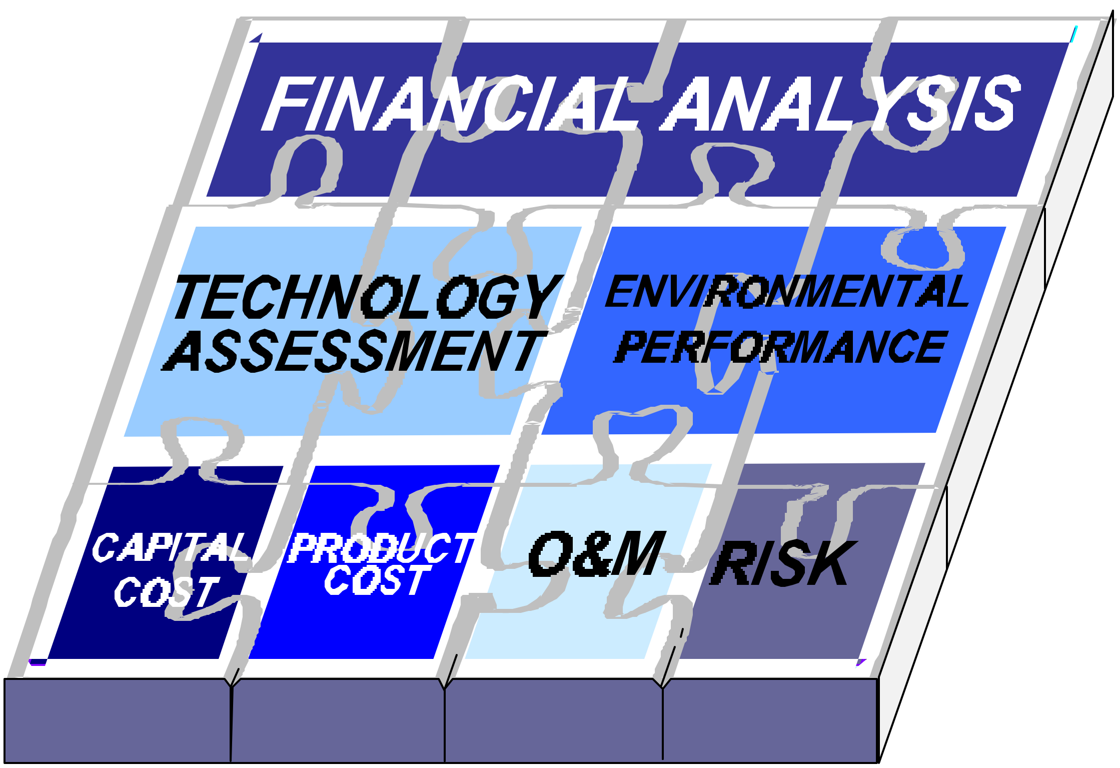
VOLUME I

Clean Coal Technology Evaluation Guide

Final Report

December 1999



VOLUME I

CLEAN COAL TECHNOLOGY EVALUATION GUIDE

FINAL REPORT

December 1999

Prepared For:

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LIST OF ACRONYMS AND ABBREVIATIONS

A/E	architect/engineer
AEO	Annual Energy Outlook
AFDC	allowance for funds used during construction
APFBC	advanced pressurized fluidized-bed combustion
ASME	American Society of Mechanical Engineers
ASU	air separation unit
ATS	advanced turbine system
BACT	best available control technology
BBFBC	bubbling bed fluidized-bed combustion
BEC	bare erected cost
CAAA	Clean Air Act Amendments of 1990
CCT	Clean Coal Technology
CFR	Code of Federal Regulations
COE	cost of electricity/Corps of Engineers (U.S. Army)
CPFBC	circulating pressurized fluidized-bed combustion
DCS	distributed control system
DEC	State Department of Environmental Conservation
DLN	dry low-NOx
DOE	Department of Energy
EIA	Energy Information Administration
EIS	environmental impact statement
EPA	Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPC	engineer/procure/construct
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
EWG	exempt wholesale generator
FBHE	fluid-bed heat exchanger
FBN	fuel-bound nitrogen
FC	fuel cost
FERC	Federal Energy Regulatory Commission
FETC	Federal Energy Technology Center
FGD	flue gas desulfurization
FWDC	Foster Wheeler Development Corporation

GDP	gross domestic product
GE	General Electric
GPIF	Gasifier Process Improvement Facility
GTCC	gas turbine combined cycle
HAP	hazardous air pollutant
HARP	heater above reheat pressure
HGD	hot gas desulfurization
HGPR	hot gas particulate removal
HHV	higher heating value
HP	high pressure
HR	heat rate
HRSG	heat recovery steam generator
HTGC	high-temperature gas cleanup
HTHP	high temperature/high pressure
I&C	instrument and control
ID	induced draft
IGCC	integrated gasification combined cycle
IGT	Institute of Gas Technology
IOU	investor-owned utility
IP	intermediate pressure
IPP	independent power producer
IRP	integrated resource planning
LAER	lowest achievable emission rate
LASH	limestone/ash
LEBS	low emissions boiler systems
LHV	lower heating value
LP	low pressure
MACT	maximum achievable control technology
MASB	multi-annular swirl burner
MWe	megawatt electric
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act of 1969
NGCC	natural gas combined cycle
NOx	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards

O&M	operations and maintenance
OD	outside diameter
OJ	operating job
OLC	operating labor charge
OP	over pressure
OTAG	Ozone Transport Assessment Group
OTR	Ozone Transport Region
PC	pulverized coal
PCD	particulate control device
PDU	process development unit
PFBC	pressurized fluidized-bed combustion
PICFB	pressurized internally circulating fluidized bed
PSC	State Public Service Commission
PSD	prevention of significant deterioration
PSDF	Power Systems Development Facility (Wilsonville, Alabama)
PUHCA	Public Utilities Holding Company Act
PURPA	Public Utilities Regulatory Policy Act of 1978
QF	qualifying facility
R&D	research and development
RACT	reasonably available control technology
RDF	refuse-derived fuel
REP	Range Estimating Program
RFP	request for proposal
RPD	restricted pipe discharge
RTI	Research Triangle Institute
SCR	selective catalytic reduction
SIP	state implementation plan
SNCR	selective non-catalytic reduction
TAG™	Technical Assessment Guide (EPRI)
TCE	total cash expended
TCLP	toxicity characteristic leaching procedure
TCR	total capital requirement
TGP	Texaco Gasification Process
THGD	transport hot gas desulfurization
TPC	total plant cost
TPI	total plant investment

TRTU	Transport Reactor Test Unit (M.W. Kellogg)
VSD	variable speed drive
VWO	valve wide open

1.0 INTRODUCTION

Coal-fired power plants will continue to provide a significant share of the nation's electrical power production well into the 21st century.(1) The changing utility and regulatory environment will provide opportunities for Clean Coal Technologies (CCTs) to serve as competitive generators in this market. This evaluation guide is to assist decision-makers in evaluating certain CCTs. It presents comparative analysis techniques and data on power generation options to meet future load growth demands. Through the use of a consistent basis for evaluating the technical, cost, and environmental performance data for CCTs, an objective process to determine the commercial potential of these technologies is available. Additionally, through interfacing with stakeholders and obtaining input and feedback on approach and results, this guide focuses on the issues most important to a decision-maker.

Recent developments in the electric utility business, both in the United States and abroad, have placed new demands on a decision-maker evaluating the application of advanced power generation technologies. Previously, the electric utility industry would evaluate competitive technologies based on a revenue requirement under regulated market economic conditions. However, the passage of the Public Utility Regulatory Policy Act of 1978 and the Energy Policy Act of 1992 has opened the electrical generation market to competition from non-utility generators. Under the direction of the Federal Energy Regulatory Commission (FERC), the landmark FERC Order 888 has mandated transmission access, wholesale competition, and federal and state actions introducing retail competition. In response to these market and regulatory changes, the power generation sector has begun restructuring, unbundling of services, mergers with and acquisitions of neighboring utilities, and, in some instances, purchases of foreign utilities. These actions are moving the sale of energy away from cost-based returns into market-based competitive pricing.

Under this new business climate there is a need for providing a decision-maker with information and methods of evaluating competing technologies that are more applicable to actual market conditions. Technology developers, financial investors, and project developers share in the need for these data to evaluate investments in power generation upgrades and additions to their utility systems. With the data forthcoming from the CCT program, a partnership of the U.S. Department of Energy (DOE) and industry, design and operational information is now becoming available to help in performing the necessary evaluations.

This report contains the technical, economic, and environmental performance data on CCTs for advanced power generation applications, along with comparative analyses to conventional technologies. The data are presented in a format to assist in the selection of power generation options for application in the year 2005. The approach presented in meeting the needs of a decision-maker consists of applying lessons learned in the CCT programs to update technical, cost, and environmental performance data on selected CCTs for use in a comparative analysis with other state-of-the-art technology options. Through the use of this information, and the methods defined for comparative analysis, a decision-maker can determine appropriate strategies for industry to promote market acceptance of CCTs. The initial slate of CCTs under consideration includes integrated gasified combined cycle (IGCC) and pressurized fluidized-bed combustion (PFBC), with comparisons to conventional pulverized coal and natural gas combined cycle technologies.

1.1 APPROACH

The approach followed in developing the CCT data and methods of analysis consists of a multi-phased study to establish key decision issues, definition of operational and economic performance data, and formatting results for use in technology evaluation. This initial evaluation guide presents data and analysis results for IGCC power generation applications using coal. Subsequently, data will be developed for PFBC technologies including bubbling and circulating bed designs.

To initiate the development of this evaluation guide, selected stakeholders were interviewed and asked to define key issues in the decision-making process. These issues were used to focus the development of technical, economical, and environmental performance data of advanced power technologies and assist in identifying CCT commercial opportunities. An iterative process was then utilized to focus the study's approach to assure acceptance of the results by industry stakeholders. The time frame for which the analyses are being conducted is 2002 to 2010, with a decision to proceed into plant startup by the year 2005.

Updated technical, cost, and environmental performance data for advanced power generation technologies were then established by applying lessons learned from CCT projects together with inputs from technology developers and users. Baseline power cycle configurations were developed based on stakeholders' feedback on application size and duty cycle. Power plant performance, cost, and environmental data for IGCC technology at nominal plant sizes in the 200 MW to 500 MW range were defined. Competitive current technology options, including conventional pulverized coal (PC) with scrubbers and natural gas-fired combined cycles (NGCC), were also defined for use as a reference for performance and economic comparison.

To assist the decision-maker in evaluating risk associated with a particular technology selection, an identification and definition of technology and cost uncertainty, at a component level, was completed.

Quantitative methods were then applied to determine the effects of risk and uncertainty on performance and the economics of commercial operation.

The economics of the advanced power generation power systems and competing power plants were then developed on a consistent basis of evaluating the capital, interest during construction, production costs, and cost of electricity (COE). Sensitivity analysis was performed to evaluate the effects on COE from variations in capacity factor, heat rate, fuel price, and capital cost. In addition, a risk assessment model, Range Estimating Program (REP), was utilized to quantify the risk associated with the contingency assigned to the capital cost estimates of the advanced power systems.

To determine the potential variation in capacity factor and heat rate, a production costing model was used to evaluate, on an hour-by-hour basis, the operating parameters faced by new generation plants in meeting the needs of a utility system under competitive dispatch conditions.

1.2 EVALUATION GUIDE OVERVIEW

The guide is arranged in three volumes, with the evaluation guide overview presented in the Executive Summary. Results of the technical, economic, and environmental performance are presented in Volume I.

Section 2.0 of this volume presents an overview of the key issues identified by power generation decision-makers. The issues range from the fundamental assessment of power generation needs to the technical or economic risk level stakeholders are willing to accept. The issues fall under the following categories: technical, economic, environmental, regulatory, and market issues. Stakeholder input and feedback on a preliminary listing of issues facing a decision-maker are presented, including the potential impacts from the deregulation of the utility industry, competition for new generation, and open access to the transmission network.

All of these issues add to the challenge of introducing new technologies into the marketplace. With the development of open competition, the current emphasis by regulators is to minimize the COE and the financial uncertainties that are associated with deregulation.

The CCTs considered for commercial viability in the evaluation's timeframe are introduced in Section 3.0 of Volume I. CCT and conventional power systems evaluations are then presented in a summary format to allow the reader to quickly obtain key decision process inputs. Brief power plant descriptions are provided with overall environmental and performance analyses, and capital and production costs for each technology.

The decision-making process includes the identification and evaluation of technical and economic risk to the investor. In Section 3.0, a risk assessment on the capital cost components associated with each of the advanced power plant configurations is defined to identify an expected cost of pushing the technology from the developmental status to full commercialization by 2002. Two methods are used to define the effect of risk on the process economics. The first provides a subjective review of specific components at risk, with identification of an appropriate process contingency to be applied as an adjustment to the project's capital cost. In this manner a decision-maker may adjust the risk contingency as the technology is demonstrated and commercialized. The second method, presented in Section 4.0, uses baseline capital and production cost for each technology to provide sensitivity of various operating parameters to demonstrate the effect of risk on the process economics. This section also provides the approach, basis, and methods that were used to perform capital and production cost evaluations, thus allowing a decision-maker an opportunity to adjust the inputs to fit the particular needs of the utility market being served. Technology evaluation results are presented in Section 5.0 in a side-by-side format for technology performance, economics, and environmental comparison.

Appendix A provides a brief discussion of environmental regulations as applied to the application of CCTs. Detailed results of the economic and financial analyses are provided in Appendix B. The Range Estimating Program used in the development of capital cost sensitivity is described in Appendix C. Appendix D provides contacts within the manufacturing, power producers, and R&D communities to assist in the decision process with up-to-date information and results from technology development and deployment.

2.0 ANALYSIS OF EXTERNAL UNCERTAINTIES

The U.S. Department of Energy (DOE) is obtaining technical, economic, and environmental performance data on Clean Coal Technologies (CCTs) through a multi-year clean coal demonstration program. Through this program, the DOE intends to make available to power generation stakeholders the types of information necessary for government and industry to promote market acceptance of CCTs. The approach applies the lessons learned in the CCT program demonstrations to update technical, cost, and environmental performance data on CCTs and prepare an information database to undertake comparative analyses with other state-of-the-art technology options. Of particular relevance to the successful commercialization of CCTs is the ability of the stakeholder to evaluate uncertainties in the process of deciding about power generation options.

The decision process of the utility planner and non-utility planner alike relies on a consistent basis for the evaluation of technical, cost, and environmental performance data for power generation technologies. Throughout this process, a decision-maker utilizes comparative analysis techniques and data to evaluate CCTs as a power generation option. As the first step, the DOE has conducted outreach activities with stakeholders to identify uncertainties or issues that are key to the decision-making process. These issues are important to the definition of the issues and bases for which a given power generation technology will be evaluated, and range from the fundamental assessment of power generation needs, to the level of technical and economic risk stakeholders may be willing to accept.

This Section 2.0 presents a brief overview of issues or uncertainties faced by the decision-maker in the selection of power generation technologies. These issues have been summarized under the following categories: technical, economic, environmental, regulatory, and market. Sections 3.0, 4.0, and 5.0 present technical, economic, and environmental performance data that may be used in the decision process to address areas of uncertainties, and as a minimum, provide the stakeholder with a baseline upon which to compare competing technologies. Some issues, especially those related to the uncertainty of future regulatory and market direction, are discussed, but it is left to the stakeholder to assign appropriate values. Issues that can be reduced to performance or economic values may be addressed through use of the performance and cost data presented in the following report sections.

Due to the high degree of uncertainty in the future market for power and the electric utility sector, the issues presented here are still evolving, and the impact of these on coal-using technologies will change over time. The analyses presented in this report focuses on supporting electrical baseload requirements in the 21st century, specifically for capacity additions and/or repowering of existing facilities for service in the year 2005.

2.1 TECHNICAL ISSUES

Technical issues are important to prospective investors in proportion to how they affect the risk inherent to an investment proposal. The advanced power generation technologies under demonstration in the CCT program have more perceived risk to the investment community than conventional power systems, e.g., subcritical pulverized coal or natural gas combined cycle. Successful demonstration of these technologies will lower the level of uncertainty to the developer, turnkey contractor, or the equipment supplier and affect the utility planner's decision to move forward. Key factors in assessing the state of technology readiness include:

- Demonstrated process and integrated plant availability.
- Manufacturers' and turnkey contractors' performance guarantees.
- Operations and maintenance costs requirements.
- Fuel flexibility.
- Energy efficiency and environmental performance.

An objective of the CCT program is the commercial deployment of successfully demonstrated technologies. The detailed technical, economic, and environmental data and experience gained during the demonstration will be vital to efforts to commercialize the technology. Meeting this objective involves complementary but distinct roles for the technology owner and the government. For the government, the purpose of its role as facilitator in technology transfer is achieved by the information being distributed to the decision-makers in a usable and timely fashion. It is the technology owner's role to retain and use the information and experience gained during the demonstration to promote the utilization of the technology in the domestic and international marketplace.

The success of the CCT program ultimately will be measured by the degree to which the technologies are commercialized both domestically and internationally and by the contribution the technologies make to the production of low-cost and clean electrical power. This goal can be reached only if the decision-maker understands that these technologies are competitive with alternative energy options through efficiency increases and enhanced environmental quality.

Clean Coal Technology Demonstration Program

Table 2-1 provides a review of the Clean Coal Technology Program's slate of 39 projects.(2) The CCT program has proven to be an effective means by which government can work cooperatively with the private sector in demonstrating new technologies for introduction into the commercial marketplace.

Table 2-1
Clean Coal Technology Demonstration Program
Project Status
(Fall 1998)

Project	Status
ADVANCED ELECTRIC POWER GENERATION	
Fluidized-Bed Combustion	
McIntosh Unit 4 PCFB Demonstration Project	Project restructured and re-sited
Tidd PFBC Demonstration Project	Final Report NTIS #DE96000650
Nucla CFB Demonstration Project	Final Report DOE/MC/25137-3046
ACFB Demonstration Project	EIS in progress
Integrated Gasification Combined Cycle	
Clean Energy Demonstration Project	Site pending
Piñon Pine IGCC Power Project	Final startup/addressing issues
Tampa Electric Integrated Gasification Combined Cycle Project	In operation
Wabash River Coal Gasification Repowering Project	In operation
Advanced Combustion/Heat Engines	
Healy Clean Coal Project	In operation
Coal-Fueled Diesel Engine Demonstration Project	Construction phase approved
ENVIRONMENTAL CONTROL DEVICES	
NOx Control Technologies	
Demonstration of Coal Reburning for Cyclone Boiler NOx Control	Project complete - Final reporting
Full-Scale Demonstration of Low-NOx Cell Burner Retrofit	Final Report NTIS #DE96003766
Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler	Final reporting
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Final Report under review
180 MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NOx Emissions from Coal-Fired Boilers	Final Report NTIS #DE94011174
Demonstration of Selective Catalytic Reduction Technology for the Control of NOx Emission from High-Sulfur Coal-Fired Boilers	Final Report NTIS #DE97050873
Micronized Coal Reburning Demonstration for NOx Control on a 175 MWe Wall-Fired Unit	Ongoing test operations

Table 2-1 (Continued)
Clean Coal Technology Demonstration Program
Project Status
(Fall 1998)

Project	Status
SO_2 Control Technologies	
10 MWe Demonstration of Gas Suspension Absorption	Final Report NTIS #DE960003270
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Final Report DOE/PC/90546-T10
LIFAC Sorbent Injection Desulfurization Demonstration Project	Final Report NTIS #DE96004421
Advanced Flue Gas Desulfurization Demonstration Project	Final Report NTIS #DE96050313
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Final Report NTIS #DE94016053
Combined SO_2/NOx Control Technologies	
SNOX™ Flue Gas Cleaning Demonstration Project	Final Report NTIS #DE94018832
LIMB Demonstration Project Extension and Coolside Demonstration	Final Report NTIS #DE93005979
SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project	Final Report NTIS #DE96003839
Enhancing the Use of Coal by Gas Reburning and Sorbent Injection	Final Report NTIS #DE96011869
Milliken Clean Coal Technology Demonstration Project	Ongoing test operations
Commercial Demonstration of the NOXSO SO_2/NOx Removal Flue Gas Cleanup System	Negotiations to re-site project
Integrated Dry NOx/SO_2 Emissions Control System	Final reporting
COAL PROCESSING FOR CLEAN FUELS	
Coal Preparation Technologies	
Development of the Coal Quality Expert	Final reporting
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Plant operations on hold
Advanced Coal Conversion Process Demonstration	Processing coal
Mild Gasification	
ENCOAL Mild Coal Gasification Project	Completed testing
Indirect Liquefaction	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Ongoing operation
INDUSTRIAL APPLICATIONS	
Blast Furnace Granulated-Coal Injection System Demonstration Project	Ongoing operation
Clean Power from Integrated Coal/Ore Reduction (COREX ®)	Baseline studies
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Final Report NTIS #DE92002587
Cement Kiln Flue Gas Recovery Scrubber	Final Report NTIS #DE94011175
Reference: Clean Coal Today, Fall 1998 Issue No. 31[2]	

Source: U.S. Department of Energy

Fourteen projects, with a total estimated cost to completion of over $4.7 billion, are demonstrating advanced electric power generation technologies in fluidized-bed combustion, integrated gasification cycle, and advanced combustion/heat engines. These technologies are characterized by high thermal efficiency, very low SO_2 and NOx emissions, reduced emissions of CO_2 solid and liquid waste reduction, and enhanced economics. The technologies are also flexible in that they can fulfill requirements in both new generating capacity "greenfield" and repowering applications. The CCT projects in this market category represent approximately 1,200 MWe of new generating capacity and 800 MWe of repowered capacity. Table 2-2 presents the DOE research goals[3] for advanced power systems as published in 1993.

Table 2-2
Research Goals for Advanced Power Systems

	2000	2005	2010	2015
Efficiency (HHV)	42%	47%	55%	60%
Emissions	1/3 NSPS	1/4 NSPS	1/10 NSPS	1/10 NSPS
CO_2 Reductions	24%	32%	42%	47%
Cost of Energy	→ 10 to 20 percent lower ←			

Source: U.S. Department of Energy

DOE-led programs support the development of Advanced Turbine Systems (ATS) on a cost-sharing basis, enabling gas turbine manufacturers to provide ATS to the commercial marketplace and establish a foundation on which DOE goals can be achieved. Objectives of the ATS program are to develop low-cost, highly efficient gas turbine systems that possess superior environmental performance. General Electric (GE) and Westinghouse are participating in the program to develop utility-scale ATS, large gas turbine combined cycle systems greater than 400 MW. Each of these systems incorporates a unique closed-loop cooling concept that improves system efficiency and maintains superior environmental emissions. Table 2-3 lists the characteristics of both GE and Westinghouse cycles.

The commercially available and demonstrated turbine technology consists of the GE 7000F in combined cycle. This system operating at Tampa Electric CCT integrated gasification combined cycle (IGCC) project is capable of producing 250 MW from gasifier syngas at a higher heating value (HHV) efficiency of 38.9 percent. The Westinghouse W501G turbine is expected to be commercially available before 2000, and because of its increase firing temperature and efficiency, the DOE HHV efficiency goal of 42 percent by 2000 should be surpassed. GE has made a commercial announcement and offering of their ATS, designated as the STAG 107H, referred to elsewhere as the "H" turbine. With the "H" technology, the DOE goal of 47 percent HHV in 2005 should be surpassed.

Table 2-3
Utility ATS Performance Characteristics

	General Electric	Westinghouse
Cycle Configuration	Combined Cycle	Combined Cycle
System Size	400 MW	440 MW
Turbine Inlet Temperature	2600EF	2700EF
Pressure Ratio	23:1	25:1
Nitrogen Oxides	9 ppm	9 ppm
Efficiency (LHV)	>60	>60

The CCT program technologies are operated at sufficient scale and in user environments to provide useful and meaningful results to assess commercial performance potential, with several of the advanced electric power generation projects only now generating operating data. Based on present utility integrated resource plans and other forecasts, this schedule is compatible with most utility expansion plans. Domestic baseload capacity increases are projected to be required about the year 2005 and extend well beyond 2010, requiring decisions on available options to take place beginning around the year 2000. For those considering repowering of existing facilities to meet the stringent year 2000 Phase II emissions requirements under the Clean Air Act Amendments of 1990, sufficient information will be available on most technology options to assist in the decision-making process.

In comparison with current coal-fueled power plants, the higher efficiencies of CCT power systems (see Figure 2-1) will contribute to both environmental performance improvements and lower overall production cost. Reductions in capital costs are also targeted through efforts to streamline process design, increase the modularity of plant design, and reduce power plant land area requirements.

Commercial availability of CCT power systems technologies in the United States is targeted for early in the next century, a period when replacement of aging power generation facilities is expected to accelerate, and when substantial new baseload capacity additions are anticipated.[1]

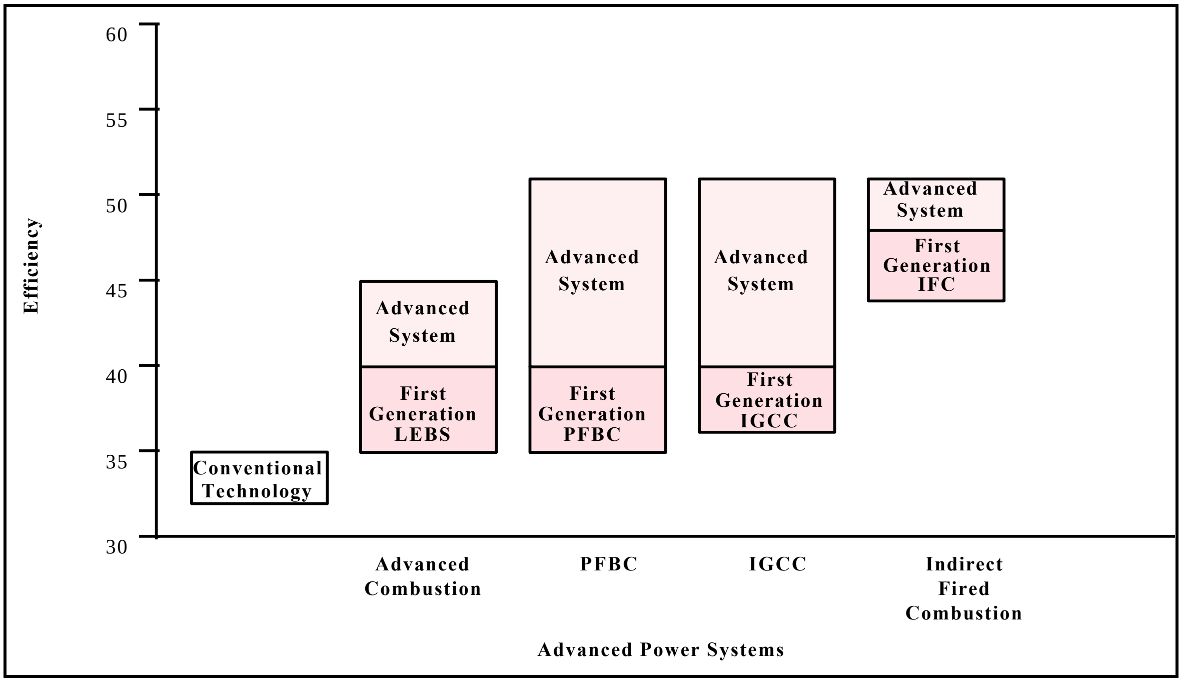


Figure 2-1
Advanced Power System Efficiency Improvements

Source: U.S. Department of Energy

2.2 ECONOMIC ISSUES

Many of the issues confronting the decision-maker are tied to evaluating a project's economic risk. From the investor's perspective, the ability to achieve project financing and investment objectives are the important measures of project viability. Economic issues include those directly related to capital and fixed operating cost, such as equipment or process availability, economy of scale, and construction and startup schedule. Variable operating costs that contribute directly to the marginal cost of electricity are affected by process performance, fuel availability and cost, and other process consumables. Key factors in assessing the economics of technology selection include:

- Capital Investment
- Construction and Startup Schedule
- Startup Costs
- Operations and Maintenance Costs
- Capacity Factor
- Saleable Byproducts
- Cost and Schedule Guarantees
- Long-Term Fuel Cost and Availability
- Financing Structure
- Hazardous Waste (where applicable)

Competition in utility generation and the exposure risks of large capital investments have led to a preference to minimize front end costs and minimize fixed and variable operation and maintenance costs. There is considerable concern in the utility industry with the potential of having “stranded investments.” These are investments that would be unable to recover capital due to changes in market competitiveness or regulations. The issue of stranded assets has recently been addressed by the Federal Energy Regulatory Commission (FERC) Final Order No. 888, discussed later in this section.

Additionally, fuel supply/fuel flexibility is essential to the long-term success of a CCT project. A project design is normally focused on a particular type of fuel. As a part of the design process, a projection of long-term fuel availability is made. Unavailability of the fuel during the economic life of the project will adversely impact the project’s performance. If a project is capable of shifting fuel types (i.e., is flexible), such long-term fuel supply risks are reduced.

Three phases of the schedule are important:

- Development schedule including the permitting.
- Construction schedule to include the release of contracts to the field.
- Startup schedule.

The final schedule guarantees are normally defined at the time of the financial closing.

Issues concerning financing structure can be defined further by the competitive factors in the financial community and by the demand side of the electrical market it serves. Issues can be summarized into the following financial issues:

- Market competitiveness
- Financing basis
- Demand forecasts
- Fuel price forecasts
- Byproduct markets
- Fuel and feed stock supply/fuel flexibility
- Regulatory uncertainties
- Cost of capital

Ultimately, the project must be competitive within the power grid served. The baseline for comparison is the existing generators on the grid selling power. From the perspective of the financial lender, the economics of the project are fundamental to the success of the project in that the financial community is looking for a reasonable return on investment. For that return to occur, the revenues and costs associated with a project must be predictable, the risk of acquiring these revenues must be understood, and the project must be economically viable, i.e., it must have the ability to meet liabilities from operating revenue. Fully defining economic risk is paramount to the capital investor.

Additionally, the "allocation of risk and project economics" is fundamental to the success of the project and, therefore, outweighs many other factors. This allocation is based on the acceptance of risk by the "appropriate party." In the case of power generation technology, acceptance is usually by the manufacturers or those parties in the business of underwriting risk through one form or another.

When a CCT is considered, the financing decision will be impacted by the amount of risk the developer, turnkey contractor, and major equipment vendors are willing to accept. The key to the resolution of economic issues is to have equity players contribute to assigning risk to the party who can best define and control it. Specifically, risks need to be identified, allocated, and assumed by the party that is most capable of dealing with the risk. In addition, the group assuming the risk must be sufficiently informed about the risk for the assumption to be credible.

Performance guarantees are the heart of the issue, and performance guarantees must be backed by credit-worthy companies or financial instruments. The most effective performance guarantees are the ones that do not immediately result in legal recourse given an unfavorable event. In the development and the acceptance of the performance guarantees, the lenders will use experts to assess the level of risk associated with each project. Performance guarantees can consider energy output (MWe or steam in pounds per hour), process efficiency, system heat rate, maintenance schedule and costs, environmental compliance, or construction schedule as examples.

Assuming the project risks have been allocated to the appropriate party, the equity investors will still need to ensure the project makes sense from an economic standpoint. For this to occur, an energy project must be competitive with the other system generators supplying the electric grid. Energy produced by the facility must be competitive such that the facility will be dispatched on the electric grid. In addition, other byproducts such as steam or chemicals must be competitively priced for revenue flow to occur.

2.3 ENVIRONMENTAL ISSUES

In the process of power generation technology selection, the decision-maker is evaluating systems that will enable utilities to meet stringent environmental requirements while providing competitive electricity prices. The technologies must produce significantly lower emissions of acid rain gases, greenhouse gases, and air toxics species than the present generation of coal-fueled power plants. Additionally, the project must be environmentally sound such that a permit can be obtained before the project is considered for financing. The financial community looks at the satisfaction of regulatory and permit issues as a prerequisite to any commitment. The permit must exist or be obtainable before the financial community will commit funds.

Specifically, the financial community will not accept any permitting or environmental risk. Construction may not start until major permits are issued and are enforceable. This means that the need to develop and obtain the environmental permits is the responsibility of the ultimate owner or the developer. In addition, from the lender's perspective, there is no "extra credit" given for developing a design that goes beyond the environmental and regulatory requirements.

At a point in time when the electric generation market is becoming more deregulated, the technology required to produce electric power has to satisfy more environmental regulatory requirements. New or modified facilities must be designed to comply with a full range of environmental regulations. The significant regulations and environmental issues may include:

- National Environmental Policy Act of 1969 (NEPA)
- Clean Air Act Amendments of 1990 (CAAA)
- Energy Policy Act of 1992 (EPAct)
- New Source Performance Standards (NSPS)
- National Ambient Air Quality Standards (NAAQS)
- Prevention of significant deterioration (PSD)
- Greenhouse gases reduction
- Hazardous air pollutants
- Acid deposition
- Water use and discharge
- Waste disposal
- Externalities

The CAAA requirements are the most extensive, and the technology needed to address these requirements offers an opportunity for CCTs to achieve a competitive advantage. The advantage to an existing generator is that the emission reductions required by existing plants would be achieved by repowering with a CCT rather than installing additional emission controls at the source. This assumption is realistic in that the CCT will meet the most stringent emission limitation expected.

A review of both existing environmental regulations and potential future environmental concerns, which may or may not impact the selection of technology, is valuable to the decision-making process. Appendix A briefly describes the environmental regulations for CCT applications. The following highlights some of the key issues.

The National Environmental Policy Act (NEPA) - NEPA of 1969 was approved into law on January 1, 1970. This Act established a national policy to promote efforts that will prevent or eliminate damage to the environment. The law required, as a part of a proposal for activities that could have a significant impact on the quality of the human environment, the submission of an Environmental Impact Statement (EIS). The EIS identifies environmental impacts that can result from a project and then provides an approach and alternatives that may be used to mitigate against the impacts. The specific requirements for the EIS have evolved and will continue to evolve. However, for CCT projects, the most significant requirements include emission streams, effluent streams, and waste streams associated with air, water, and solid waste. The EIS will identify the quantity, composition, and frequency of discharges. The evaluation of discharges is essential to ensure the project meets discharge limitations.

Clean Air Act Amendments of 1990 (CAAA) - CAAA was signed into law in November of 1990 with a goal to reduce pollution from gaseous emissions by 56 billion pounds a year. The control of pollutants that can contribute to acid rain is subject to Title IV of the CAAA. These regulations include a two-phase, market-based approach to reduce SO_2 emissions from power plants and provides for the requirement to have an allowance trading system. Reductions of oxides of nitrogen will also be achieved, but through performance standards set by the Environmental Protection Agency (EPA). Title III of the CAAA identifies a "major polluter" as a source that will emit more that 10 tons per year of any one of 189 listed hazardous pollutants or more than 25 tons per year of any combination of hazardous air pollutants. Other requirements of the CAAA cover non-attainment areas, permitting, motor vehicles, and stratospheric ozone depletion.

The Energy Policy Act of 1992 (EPAct) - EPAct was signed into law in October of 1992. Under Title XVI, Global Climate Change is addressed. Among the provisions, Title XVI calls for DOE to establish a voluntary reporting system for participants to submit information on their greenhouse gas emissions. On October 19, 1993, the Climate Change Action Plan, which described the actions that would be taken to reduce greenhouse gas emissions, was released by the President and Vice President. The Plan describes nearly 50 new and expanded initiatives that would reduce emissions. Included in those initiatives was the use of CCTs.

New Source Performance Standards (NSPS) - The EPA has issued a series of standards that address a number of basic industrial categories. NSPS reflect the maximum degree of emission control that can be achieved by an industry through direct emission control, operation, and other available methods. NSPS are available for the various fuel sources and are used as a part of the permitting process. NSPS are applicable to the following combustion sources:

- Fossil fuel-fired steam generators
- Electricity utility steam generating units
- Industrial - commercial - institutional steam generating units
- Incinerators
- Municipal waste combustors
- Sewage treatment plants
- Gas turbines

National Ambient Air Quality Standards (NAAQS) - The Clean Air Act directs EPA to identify and set national ambient air quality standards for pollutants that cause adverse effects to public health and the environment. EPA has set national air quality standards for six common air pollutants: particulate matter (measured as PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ground-level ozone (O_3) (smog), and lead (Pb). For each of these pollutants, EPA has set health-based or "primary" standards to protect public health, and welfare-based or "secondary" standards to protect the environment (crops, vegetation, wildlife, buildings and national monuments, visibility, etc.). Additional requirements will be placed on facilities based on whether or not the facility will be located in an area that is meeting the ambient air quality standards. If the NAAQS are being met in an area of a proposed facility, the facility will be subject to the requirements of the attainment area (i.e., prevention of significant deterioration of air quality). If requirements are not being met, non-attainment area requirements will be applicable. In non-attainment areas, the control equipment should be designed to achieve the lowest achievable emission rate (LAER), which is the most stringent of either any State's Implementation Plan emission rate or any demonstrated technology, but in no case less stringent than NSPS. The non-attainment area requirements also specify that emissions from the new source be more than offset by a reduction in emissions from existing sources in the area.

Prevention of Significant Deterioration (PSD) - PSD requirements are applicable to major modifications or new major stationary sources being located in areas that are meeting NAAQS. PSD requirements are developed around the concept of installing the best available control technology (BACT). By definition, CCTs should qualify as BACT, which is the maximum degree of emission reduction determined on a case-by-case basis for new sources in clean air areas with cost, energy, and technical feasibility taken into account, but in no case is BACT less stringent than NSPS. PSD requirements also include air quality dispersion modeling to estimate compliance with PSD increments and NAAQS. Preconstruction monitoring (both ambient air pollutants and meteorology) may be required for comparing existing ambient air quality to NAAQS and for dispersion modeling. An analysis of impairment to visibility, soils, and vegetation that would occur as a result of the source; and air quality impacts of projected general commercial, residential, industrial, and other growth associated with the source are also required.

Greenhouse Gases - International agreements have targeted CO_2 for reduction to pre-1990 levels. The overall effect of these international agreements is that use of fossil fuels must be made more efficient than existing operations. U.S. policy on climate change calls for signing a legally binding treaty to reduce greenhouse gas emissions. A Senate resolution (S.Res. 98) states that the Senate will not approve a treaty that does not set identical emissions levels and compliance timetables for all parties. The resolution endorses the scientific consensus on climate change, and while it throws a spotlight on developing countries, it still allows the United States negotiating flexibility. In December 1997, the United States agreed in principle to the Kyoto Protocol, committing to a 7 percent reduction from its 1990 greenhouse gas emissions by a 2008 to 2012 commitment period. Congressional approval is pending.

Hazardous Air Pollutants - Title III of the CAAA covers the emissions of hazardous air pollutants (HAPs) from stationary sources. This has the potential of requiring power plants to control emissions of HAPs and to perform risk assessments of the most exposed individual if required by EPA. An Electric Power Research Institute (EPRI) report, “Electric Utility Trace Substances Synthesis Report” (TR-104614, November 1994), indicates the emissions of HAPs from power plants are quite small -- in fact, just over half the values previously estimated by EPA. The EPA is required under the CAAA to perform two studies on power plant HAP emissions, one regarding the emissions of mercury from power plants, and the other on all other HAP emissions from utility sources. The final report on HAPs, including mercury, was sent to Congress. The regulatory approach EPA plans to take is to defer imposing HAP emissions from utilities at this time and further study the emissions from utility sources.

Acid Deposition - Title IV of the CAAA relates to acid deposition. Phase I SO_2 emission requirements are being met primarily by fuel switching and/or blending, with some utilities opting for flue gas desulfurization (FGD) systems to take advantage of bonus allowances for early compliance with the Phase II requirements. The indications are that Phase II requirements for the utilities will be a test of the use of the allowance system. Utilities are expected to be purchasing excess allowances during Phase I and saving them for use in Phase II. Many utilities will be able to postpone making a decision on the method to be used to comply with the allowance program, whether it is the further use of fuel switching, or the installation of FGD scrubbers (which are also being demonstrated in the CCT program), or repowering existing sources with a CCT system with its inherently low SO_2 emission rate. The benefits of CCT are seen in the emission projections that are lower than emission rates projected by competitive technologies. Phase II

NOx emission regulations are established for the various boiler types with the emission limits based on combustion controls, coal or natural gas reburning, or selective catalytic reduction.

Water - Water-related requirements such as water usage may be a significant issue that impacts the environmental permitting. For example, the concept of zero discharge may impact the handling of the process water. The trend in this country and North America in general is toward the reduction of water usage.

Waste - A final area of concern relates to the requirements to reduce the quantity of the waste that is being discharged. The trend is toward developing a process that is capable of zero discharge. New projects need to look at the beneficial uses of the solid waste, such as concrete production road construction or use of sulfur as the feedstock for process plant operation. The challenge will be to encourage use of byproducts in these markets and to develop additional markets.

Environmental Externalities - The costs to society because of increased health care, depleted resources, and a general reduction in quality of life are environmental externalities. However, the consideration of environmental externalities has not yet been a major influence in the selection of technology for electrical power generation. The categories of environmental externalities range from measured impacts on crops, fish, recreational opportunities, and visual aesthetics. The trend away from reflecting environmental costs in utility decisions is occurring due to the ratepayer and competitive pressure to reduce the cost of power.

Future Environmental Concerns

At the present time, the uncertainties of future pollution control plans discussed below cause concerns that will have to be addressed if they become an EPA standard. In fact, the more stringent standards will likely affect existing sources as well as future sources. The future sources will have to use the emission offsets from the existing sources against new sources. There has not been any indication of the direction that EPA is heading, and it is difficult to anticipate what the future requirements may be, or the effect. Nevertheless, the future emissions from a new or repowered plant with a CCT will be less than the emissions from the existing plant.

Table 2-4 provides a brief implementation schedule for some of the CAAA Titles.

Table 2-4
CAAA of 1990 Summary Schedule

Title	Phase	Poll	Description	Sources Affected	Regs. Due	Implement Date
I			OZONE NON-ATTAINMENT (NOx) (OTR (4) sources only)			
	1	NOx	RACT	All major sources (1)	1993	5/31/95
	2	NOx	Meet ambient air quality standards (2)	>250 10^6 Btu/h heat input & >15 MW	1997	5/1/99
	3	NOx	Meet ambient air quality standards (2)	>250 10^6 Btu/h heat input & >15 MW	2001	5/1/03
III			HAZARDOUS AIR POLLUTANTS (HAPs)			
		HAPs	Final Report to Congress on Utilities HAP emissions.	Utility boilers, if EPA decides that HAP emissions pose a risk.	Pending study	
		HAPs	Maximum Achievable Control Technology (MACT)	Utility boilers, if EPA decides that HAP emissions pose a risk. Final Air Toxic Regs	11/15/2000	2003
IV			ACID DEPOSITION			
	1	NOx	LNB Technology (3)	Group 1 175 T-fired & dry bott/wall-fired blrs (3)		1/1/96
	1	SO_2	Allocation System	Units >100 MW & emitting >2.5 lb/10^6 Btu		1/1/95
	2	NOx	Best system in cost comparable to Ph1 LNB (3)	Group 2 blrs >25t NOx/yr, 2000 units (3)	1/1/97	1/1/00
	2	SO_2	Allocation System	Units >25 MW		1/1/00
V			PERMITS	Operating permits for all sources		11/95

Notes:
(1) In PA facilities emitting 100 tons or more of NOx/yr & in NJ facilities emitting 25 tons or more of NOx/yr.
(2) Applicable in the 5 month period (May-Sept) with RACT year around.
(3) Affects utilities outside the Ozone Transport Region (OTR) as Title I is more stringent than Title IV for OTR affected utilities.
(4) Northeast OTR is comprised of northern Virginia through Maine including Washington DC. In order for the OTR to meet ambient air quality standards, the Ozone Transport Assessment Group is considering expanding the area covered to those upwind states bordering the Mississippi River eastward and Texas.
(5) Title II addresses provisions relating to mobile sources.

Ozone Non-Attainment - Title I of the CAAA addresses the issue of non-attainment, that is, those areas that are not meeting ambient air quality standards. The area of concern in this regard is the ozone non-attainment area. Within ozone non-attainment areas, the concern is that NOx emissions are being considered as precursors to ozone generation, and further control of NOx emissions may be forthcoming. In the Northeast Ozone Transport Region, a future requirement limiting NOx emission rates to 0.15 $lb/10^6$ Btu will be imposed in order to meet ozone standards in the region.

Ozone NAAQS - EPA is phasing out and replacing the previous 1-hour primary ozone standard with a new 8-hour standard to protect against longer exposure periods. EPA is setting the standard at 0.08 parts per million (ppm). EPA will designate areas as non-attainment for ozone by the year 2000 (using the most recently available three years' worth of air quality data at that time). Areas will have up to three years (or until 2003) to develop and submit state implementation plans (SIPs) to provide for attainment of the new standard. The new standards will not require local emission controls until 2004, with no compliance determinations until 2007. The Clean Air Act allows up to 10 years from the date of designation for areas to attain the revised standards with the possibility of two one-year extensions. (This regulation is currently under appeal.)

Ozone Transport Assessment Group (OTAG) - Ozone is a pollutant that travels great distances and it is increasingly clear that it must be addressed as a regional problem. For the past two years the EPA has been working with the 37 most eastern states through the OTAG in the belief that reducing interstate pollution will help <u>all</u> areas in the OTAG region attain the NAAQS. A regional approach can reduce compliance costs and allow many areas to avoid most traditional non-attainment planning requirements. The OTAG completed its work in June 1997 and forwarded recommendations to the EPA. Based on these recommendations, the EPA proposed rulemaking (October 10, 1997, 40 CFR 52) requiring states in the OTAG region that are significantly contributing to non-attainment or interfering with maintenance of attainment in downwind states to submit SIP revisions to reduce their interstate pollution. The EPA issued the final rule in September 1998. (This regulation is currently under appeal.)

PM-2.5 NAAQS - EPA is making more stringent the current particulate standard from PM 10 down to PM 2.5 and smaller. EPA revised the PM standards by adding a new annual $PM_{2.5}$ standard set at 15 micrograms per cubic meter ($\mu g/m^3$) and a new 24-hour $PM_{2.5}$ standard set at 65 $\mu g/m^3$. The EPA will make designation determinations (i.e., attainment, non-attainment, or unclassifiable) within two to three years of revising a standard. A comprehensive monitoring network will be required to determine ambient $PM_{2.5}$ particle concentrations across the country. Monitoring data will be available from the earliest monitors by the spring of 2001, and three years of data will be available from all monitors in 2004. EPA will make the first determinations about which areas should be designated non-attainment status by 2002. States will have three years from the date of being designated non-attainment (or until between 2005 and 2008) to develop pollution control plans and submit them to EPA showing how they will meet the new standards. Areas will then have up to 10 years from their designation as non-attainment to attain the $PM_{2.5}$ standards with the possibility of two one-year extensions. (See Appendix A for additional information.) (This regulation is under appeal.)

SO_2 NAAQS - In January 1997, EPA proposed a new program to address the potential health risks posed to asthmatics by short-term peak levels of sulfur dioxide in localized situations. If implemented, this standard could affect sources with a potential to produce high concentrations of short-term bursts of SO_2 emissions.

Haze - The EPA proposed regional haze regulations to address visibility impairment. The proposed regulations will protect specific areas of concern, known as "Class I" areas. The Clean Air Act defines mandatory Class I Federal areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks. There are 156 of these areas protected under the existing visibility protection program. The proposed regional haze regulations apply to all states, including those states that do not have any Class I areas. State and local air quality agencies will implement the proposed regional haze program through revisions to their SIPs. The states will make decisions about specific emission management strategies.

NOx NSPS - The EPA revised the Standards of Performance for Nitrogen Oxide emissions from new fossil-fuel-fired steam generating units. The emission limit is that after July 9, 1997 no affected unit shall be constructed, modified, or reconstructed such that the discharge of any gases contain nitrogen oxides in excess of 1.6 pounds per megawatt-hour) net energy output. Net output means the net useful work performed by the steam generated, taking into account the energy requirements for auxiliaries and emission controls. For units generating only electricity, the net useful work performed is the net electrical output (i.e., net busbar power leaving the plant) from the turbine generator set.

2.4 REGULATORY ISSUES

The electric utility industry of today has evolved out of a series of changes in the Public Utilities Holding Company Act (PUHCA). This model was predicated on the management of a number of monopoly generating and distribution utilities that were charged with the requirement to serve, in exchange for the exclusive right to a service territory. This started to change with the passage of the Public Utilities Regulatory Policy Act of 1978. This change has accelerated since the latest enabling legislation, the Energy Policy Act of 1992.

The utility industry has responded to the changing legislative agenda with mixed reactions. In some cases, there is aggressive restructuring of the business designed to anticipate the direction industry will take. In other cases, utility companies are taking more of a "wait and see" attitude. Today, the utility industry is made up of investor-owned, government-owned, and independent power producers. The final direction to be taken by industry will not be clear for a number of years pending interpretation of the new regulations by industry, legislatures, regulators at the federal and state levels, and the courts.

Role of Federal Policies

The Federal Power Act supported self-sufficient, vertically integrated electric utilities, in which generation, transmission, and distribution facilities were owned by a single entity and sold as part of a bundled service (delivered electric energy) to wholesale and retail customers. Most electric utilities built their own power plants and transmission systems, entered into interconnection and coordination arrangements with neighboring utilities, and entered into long-term contracts to make bundled sales of generation and transmission to municipal, cooperative, and other investor-owned utilities (IOUs) connected to each utility's transmission system. Each system covered a limited service area. This structure of separate systems developed primarily because of the cost and technological limitations on the distance over which electricity could be transmitted. Through much of the 1960s, utilities were able to avoid price increases in electricity and still achieve increased profits, because of substantial increases in scale economies, technological improvements, and only moderate increases in input prices.

The Public Utilities Regulatory Policy Act (PURPA) of 1978 began a wave of change throughout the electric utility industry. This legislation opened the electrical generating market to independent generators. The most significant was the emergence of the independent power producer (IPP), a non-utility producer of electric power. The wave of non-utility generators has been responsible for a significant number of the new generating assets built since 1985.

In enacting PURPA, Congress recognized that the rising costs and decreasing efficiencies of utility-owned generating facilities were increasing rates to consumers. In particular, Congress sanctioned the development of alternative generation sources designated as "qualifying facilities" (QFs) as a means of reducing the demand for traditional fossil fuels. PURPA required utilities to purchase power from QFs at a price not to exceed the utility's avoided costs and to sell backup power to QFs.

Legislation continuing this fundamental change in the utility industry was the Energy Policy Act of 1992 (EPAct). EPAct introduced a number of changes to the Federal Power Act, PUHCA, and PURPA. These changes address wholesale wheeling and integrated resource planning, and promote energy efficiency. In addition, the EPAct established a new category of non-utility generators, exempt from PUHCA, the exempt wholesale generators (EWGs). The EPAct also expanded FERC's authority to order utilities to provide wheeling service to companies that generate energy for resale.

Regulation changes intended to increase the amount of free-market competition in the electric power industry are beginning. To date, the broadest action is FERC's Order No. 888 Final Rule, issued April 24, 1996, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities." This rule requires all public utilities that own, control, or operate transmission for interstate commerce to have open access non-discriminatory transmission tariffs that contain minimum terms and conditions of service. The rule also permits for the recovery of legitimate, prudent, and verifiable stranded costs associated with providing open access and transmission service. The object of this action is to promote competition in the wholesale bulk power market and provide consumers with more efficient, lower cost power. Under this rule competition in the electric utility market has been established. Public utilities have already responded by filing wholesale open access tariffs. It has been estimated by FERC that the potential benefits from this rule will be approximately $3.8 to $5.4 billion per year in cost savings.

State Regulatory Issues

The role of the state in the regulatory area is also changing. Changes in the federal law are prompting the states to look at their role as regulators. Some states are already moving to deregulate. Wheeling of power and free access to the distribution grid for EWGs is beginning. Many electric utilities are restructuring in anticipation of changes in their operation. States are addressing issues of integrated resource planning (IRP), wholesale wheeling, rate setting and cost disallowances, retail sales, and stranded capital.

Essentially, IRP provisions establish ratemaking standards that encourage utilities to use demand side management and efficiency measures to meet their customers' needs. The approach treats supply and demand side resources on an equal basis. IRP will provide utility companies with an incentive to look at efficiency improvements.

Wheeling and free access to the utility distribution grid is at the core of the deregulation issue. The EPAct provides the owners of facilities generating electricity for sale or resale with the means to request FERC to grant transmission access. As a part of the deregulation process, the Act requires that the owners first negotiate for 60 days before a complaint is filed with FERC. In addition to wholesale wheeling, EPAct encourages the states to look at retail wheeling. It should be noted, the Act prohibits FERC from ordering retail wheeling. The outcome of the wheeling issue as provided by FERC Order No. 888 will significantly set the form of the utility industry.

2.5 MARKET ISSUES

Recent developments affecting the electric utility business make it essential that the investor evaluate power generation technologies on the basis of market requirements. In the past, the introduction of a technology would, in most cases, be the responsibility of the utility itself. However, in today's market environment, investments in new technology clearly favor those utilities that have a sound balance sheet, and in the case of independent producers, are shared between developers and investors. Successful projects require addressing many fundamental issues such as those listed in Table 2-5.

Key market issues affecting power generation decision-makers for the foreseeable future include:

- Deregulation of the utility industry
- Future energy demand
- Competition for new generation
- Open access to the transmission network
- Maintaining existing generation as long as possible
  - Wholesale market clearing
  - Costs of generation
  - Access to capital

Although deregulation is in the process of sorting itself out at the federal and state level, the PURPA of 1978 has enabled many private producers of generation to enter the market, and provide competition in the building of new generating facilities. The impact of PURPA has been one of inconsistency in the pricing of electricity, and the recent state rulings voiding PURPA-based contracts have put a question on private power initiatives.

Table 2-5
Project Finance Fundamentals

Partial Checklist for Successful Project Facilities	
	A credit risk rather than an equity risk is involved.
	A satisfactory feasibility study and financial plan have been prepared.
	The cost of feedstock material to be used by the project is assured.
	A supply of energy at reasonable cost has been secured.
	A market exists for the product, commodity, or service to be produced.
	Transportation is available at a reasonable cost to move the product to the market.
	Adequate communications are available.
	Building materials are available at the costs contemplated.
	The contractor is experienced and reliable.
	The operator is experienced and reliable.
	Management personnel are experienced and reliable.
	Contractual agreement among joint venture partners is satisfactory.
	A stable and friendly political environment exists; licenses and permits are available.
	There is no risk of expropriation.
	Country risk is satisfactory.
	Sovereign risk is satisfactory.
	Currency and foreign exchange risk have been addressed.
	The key promoters have made an adequate equity contribution.
	The project has value as collateral.
	Satisfactory appraisals of resources and assets have been obtained. Adequate insurance coverage is available.
	Force majeure risk has been addressed.
	Cost overrun risk has been addressed.
	Delay risk has been addressed.
	The project will have an adequate ROE, ROI, and ROA for the investors.
	Inflation rate projections are realistic.
	Interest rate projections are realistic.

Table 2-5 (Cont'd)
Project Fundamentals

Characteristics	
If the following characteristics are applicable, the transaction may be project financible:	
	Sufficient sponsor equity available
	Strong, experienced project participants
	Strong project cash flows & DSCR projections
	Proven technologies and processes
	Fixed-price, turnkey EPC contract
	Reliable feedstock & fuel agreements
	Fixed-price O&M agreement
	Reliable offtake agreements
	Country and sovereign risk acceptable *(if applicable)*
	Currency & interest rate risk mitigatable *(if applicable)*

Source: The Bank of Tokyo-Mitsubishi, Project Finance Department

Energy Outlook

Market potential for CCTs will be significantly affected by the demand for new and repowered power plants to meet expected growth in electrical consumption. Over the past decade electricity sales have grown at a 2 to 3 percent annual rate. This growth has been steady overall and in parallel with the growth in real gross domestic product (GDP). Present estimates indicate a GDP growth of 2.1 percent a year between 1997 and 2020. The Energy Information Administration (EIA) Annual Energy Outlook 1999[1] presents projections and analyses of energy supply, demand, and prices through 2020, based on the results from EIA's National Energy Modeling System. To meet future demand requirements and replacement of retiring units, EIA projects the need for 363 gigawatts by 2020 (equivalent to 1,210 new 300 MW power plants), as shown in Figure 2-2. This projection is based on nominal values of growth, retirement of current generating capacity including 50 gigawatts of nuclear capacity and 76 gigawatts of fossil-steam capacity. Of the 155 gigawatts of new capacity required after 2010, approximately 16 percent will be needed to replace the loss of nuclear capacity.

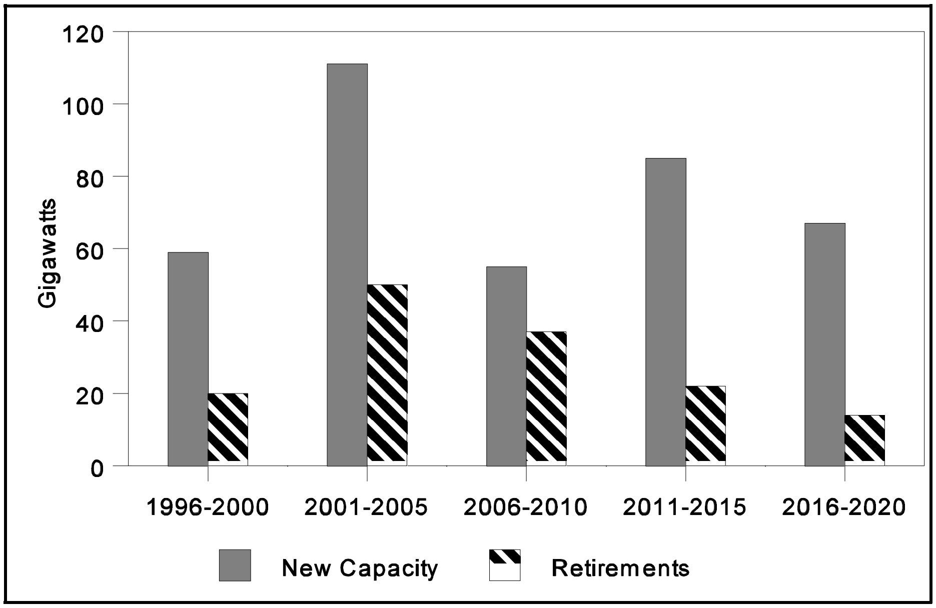


Figure 2-2
EIA Projected Capacity Additions

EIA's 1998 projections reflect some of the impacts from deregulation of the utility industry, specifically for those states where restructuring plans are in place. Estimates of this impact are subject to market developments as required by FERC's Order Nos. 888 and 889 and state and federal policies. However, it can be assumed that deregulation will continue to push electricity prices lower, may improve capacity utilization in existing facilities, and will affect unit retirements.

Repowering Opportunities

EIA's projections(1) for the 1996 to 2020 time frame indicate that utilities are expected to repower or life-extend 232 gigawatts or 30 percent of current capacity. Refurbishment of existing power plants is projected to include 381 coal-, 190 gas-, and 40 oil-fired generators at a nominal cost of $260 per kW. A review of the Electric Plant Data Base(4) provides power plant characteristics of potential repowering candidates including unit size and age. The following figures represent the results of this review:

- Figure 2-3 illustrates the distribution of units by MWe rating. Note that a large number of units exist that are smaller than 200 MWe; the median size unit appears to be between 150 and 200 MWe in size.

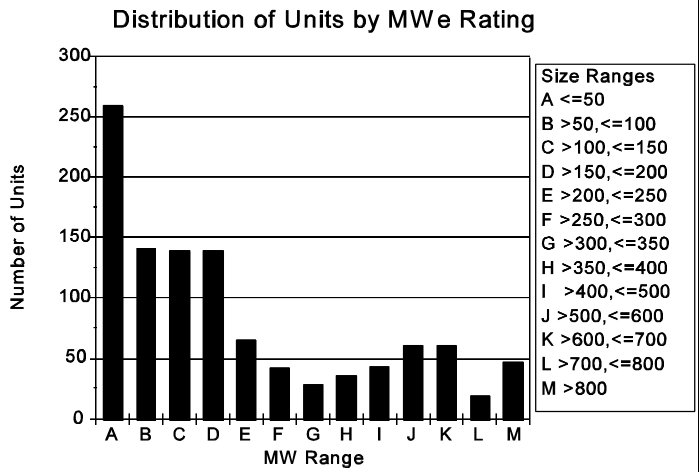


FIGURE 2-3

C Figure 2-4 is similar to Figure 2-3, but presents groups of units, each with individual nameplate ratings in the ranges as shown in the figure. These data are significant as they reflect the utility design approach to replicate plant units to gain efficiencies in capital and operational costs. Again it may be noted that a large number of units exist in the <200 MWe size, and that a median unit size for the population of groups is between 150 and 200 MWe (individual unit rating).

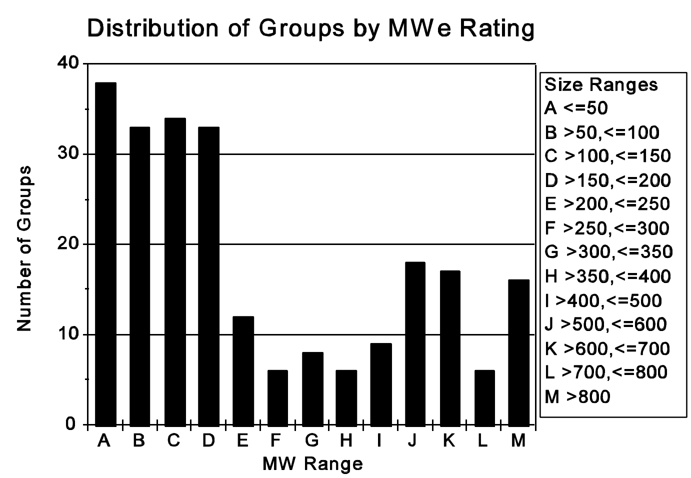


FIGURE 2-4

- Figure 2-5 is basically the same as Figure 2-4, but has additional information in that each data bar is broken into segments based on the year the unit entered service. This figure shows trends of unit size by year of service entry.

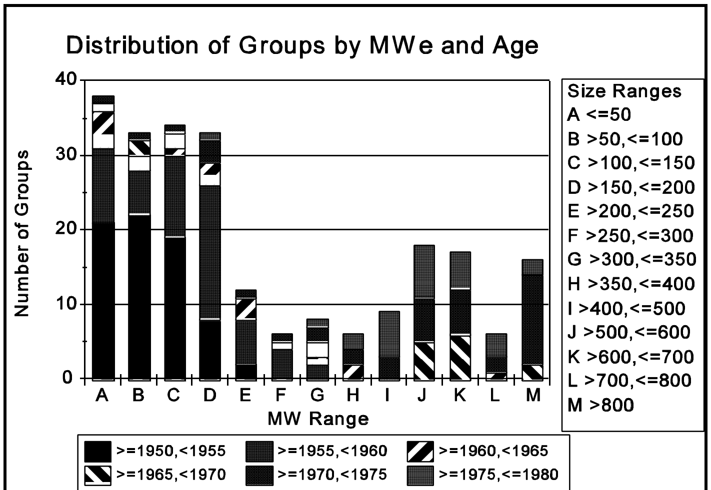


FIGURE 2-5

Of particular interest are units in the 100 to 200 MW size range. This consideration is based on the number of units in the range, and the fact that the median size unit appeared to be in this range. The next series of figures illustrates the results of this effort.

- Figure 2-6 presents the number of units as a function of the year of commissioning, thus reflecting the size vs. age of the unit population. The mid and late 1950s represented peaks of activity in power plant commissioning in this size range.

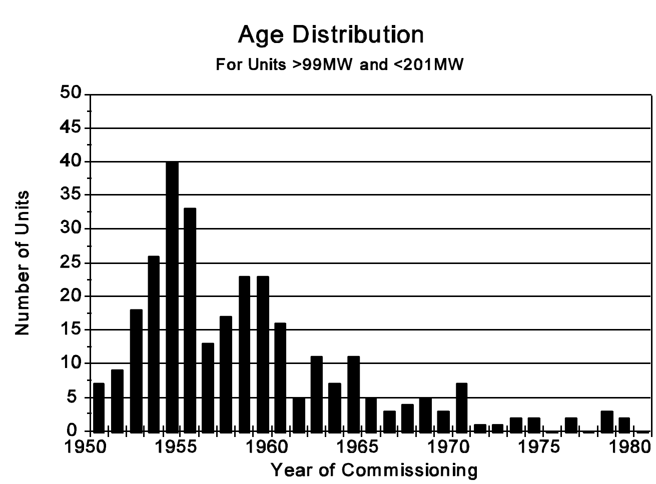


FIGURE 2-6

C Figure 2-7 presents unit sizes of discrete internals over the 100 to 200 MW span. Certain sizes appear to be more prevalent than others, clustering at 100-110, 120-125, 170-175, and 190-200 MWe. This may reflect the availability of standard frame sizes for turbine generators.

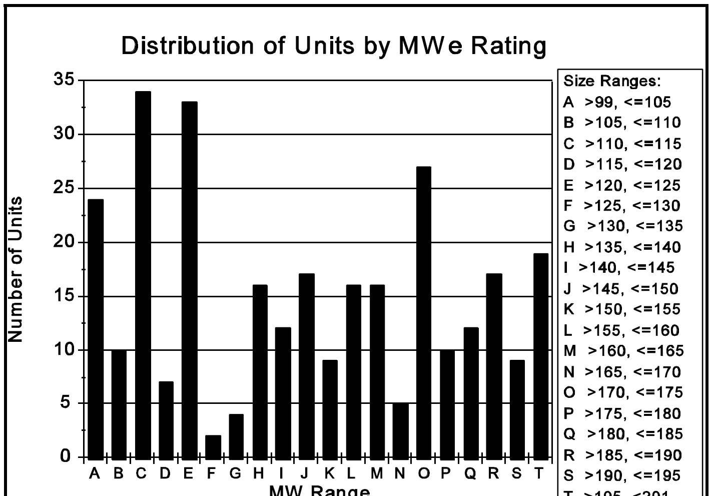


FIGURE 2-7

Based on a review of the data it can be surmised that a considerable population of existing coal-fired power plants can be considered candidates for repowering. These facilities are characterized by unit capacity of 150 to 175 MW and steam turbine conditions of 1800 psig/1000 EF/1000 EF. Repowering this class of power plant with advanced coal-fired technologies has been shown[5] to provide competitive advantages in performance, emissions, and production costs when compared to conventional technologies. Final selection of repowering technology is specific to the site and power equipment condition, along with the required benefits needed for competitive operation.

The issues and projections presented add to the challenge of introducing new technologies into the marketplace. With the competition, the current emphasis by regulators to minimize the cost of electricity, and the financial uncertainty associated with deregulation, new technologies must compete on a playing field that is changing day by day. It should be recognized by the promoters of new technologies, and the financial institutions needed to fund them, that “business as usual” in the utility field is over.

Several changes in utility business affect the decision process of introducing new technologies into the market. First and foremost was the introduction of the PURPA of 1978. When that law passed, new generation could now compete against utility-built generation, so that the utility was not the only source of electric generation in a particular service territory. The guiding principle behind this competition was the principle of "avoided costs." Under this theory of energy pricing, generation facilities that met certain standards were entitled to the highest running costs on the utility system as payment for that energy. As more and more private generation was added, the cost displacement became lower and lower until it was no longer possible to build a new facility at that price. A second item of change is the financial structure upon which new generation is based and the ability to achieve a revenue stream large enough to cover all debt, operating expenses, and return sufficient funds to warrant the investment.

One additional issue is the relationship among vendors, utilities, and the financial community. Each has its own particular investment needs, and these are not always compatible. In summary, the stakeholder in the utility business must be aware of many factors when planning new generation. The opportunities available could open the door to new technologies that can demonstrate increased efficiencies at reasonable costs. Added to all of this is the need to recognize the costs associated with environmental concerns. The Clean Air Act Amendments of 1990 resulted in trading in allowances as utilities were mandated to meet certain requirements. There is still uncertainty in that procedure with only minor adjustments and trading taking place.

New issues have been surfacing that make it even more important that the financial community is able to compare one type of technology with another. Open access to the transmission network will lead to a gradual shifting of system load characteristics as low-cost utilities capture more of the load. This will allow major electrical consumers to shop around until the lowest cost power can be found. However, this may also lead to dislocations in the power sector, with a weeding out and consolidation of many utility companies. This change in regulator's thinking is a major shift in utility planning functions. How this aspect of utility business will play out is still open to question.

3.0 TECHNOLOGY EVALUATIONS

Clean Coal Technologies (CCTs) include a range of products and processes designed to reduce the impact of fossil fuel combustion on the environment. CCTs couple superior environmental performance with the goal of power generation costs that will be competitive with those of existing technologies the CCTs will replace. Section 3.1 provides a review of goals and objectives for commercial deployment of advanced power generation systems as envisioned by the DOE. Section 3.2 provides the decision-maker with a subjective review of potential risk and associated cost implications. An overall view of the expected performance and cost for two advanced power technologies, including integrated gasification combined cycle and pressurized fluidized-bed combustion, are provided in Section 3.3.

3.1 ADVANCED POWER SYSTEMS REVIEW

The following subsections present a general review of performance, environmental, and cost goals to assist in the decision process regarding commercial application of advanced power systems. Initial discussions focus on the integrated gasification combined cycle (IGCC), with subsequent sections presenting data on pressurized fluidized-bed combustion (PFBC). Information is based on the U.S. Department of Energy's Office of Fossil Energy, Coal and Power Systems programs and the Clean Coal Technology demonstration programs.

3.1.1 Integrated Gasification Combined Cycle

IGCC technology reached a significant milestone along the path to total commercialization because of the timely commercial operation of three IGCC plants supported by the CCT program. These CCT plants demonstrate integrated operation in commercial power generation service, which minimizes technical and financial risk for subsequent plants. Therefore, IGCC technology warrants consideration for new source power generation.

Coal gasification technology for IGCC is a pressurized devolitalization, partial oxidation, and steam reaction process. Coal, an oxidant (air or oxygen), and steam are fed to the reactor where gasification takes place, as shown in Figure 3-1. The coal is heated in the process by partial oxidation, then gasified. The raw fuel gas, consisting of a mixture of H_2, CO, CH_4, CO_2, H_2O, sulfur compounds, trace materials, and in some cases N_2, is then sent to a cleanup process where the sulfur can be removed and recovered as salable sulfur or sulfuric acid. The cleaned fuel gas is routed into the gas turbine generator's combustor where it is mixed with air and burned. The hot gas then expands through the gas turbine to produce electric power. The heat remaining in the exhaust from the gas turbine is used to produce steam in a heat recovery steam generator, a type of boiler with special features to enhance heat recovery from the exhaust. The steam is routed to a steam turbine generator, producing additional electric power, which makes an IGCC very energy efficient (low heat rate).

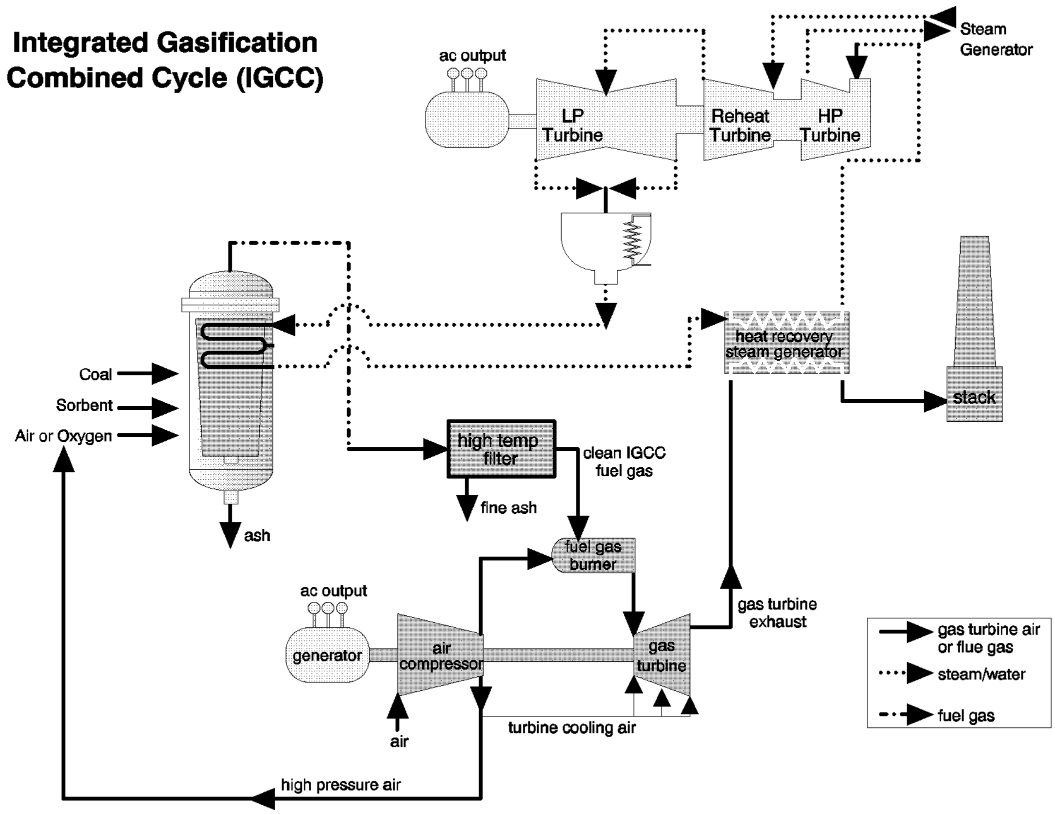


Figure 3-1
Integrated Gasification Combined Cycle

Typically, the gas turbine part of the plant produces about twice the electric power as the steam turbine part of the plant. The gas from the heat recovery boiler is exhausted by way of the plant's stack.

Coal gasification allows generating companies to use coal for a variety of applications, particularly applications not amenable to traditional coal combustion. Traditional coal-based power generation commonly calls for a relatively large (over 250 MW output) pulverized coal (PC) plant that operates as a baseloaded unit. IGCC is an attractive alternative to PC plants. IGCC can economically meet emission levels far below NSPS requirements, and produce only a small amount of inert slag solid waste. In some IGCC applications (oxygen-blown units), the sulfur in the coal feed is recovered as sulfuric acid or elemental sulfur.

The attractiveness of IGCC as a power producer has progressed toward full commercial acceptance, as shown in Table 3-1 and Figure 3-2, and is projected by the DOE to improve further through 2010. The Cool Water Project was the first commercial demonstration of integrating a gasifier with a combustion turbine in the United States. It had an efficiency of about 32 percent HHV, and overnight construction cost of approximately \$2,500/kW in 1990 dollars. Following Cool Water, the average cost of IGCC CCT projects has come down to about \$1,500 with combined cycle efficiencies approaching 40 percent HHV, primarily due to utilization of second-generation gasifier concepts and improved gas turbine performance. For the future, the DOE has formulated its IGCC Program Plan[(3)] goals to enable advanced plant performance to reach 42 percent HHV efficiency and \$1,250/kW by 2000, and greater than 50 percent and \$1,000/kW by 2008 (in 1999 dollars) as shown in Table 3-2. The DOE also projects the emissions of these future plants to be less than one-tenth of federal regulations as established under New Source Performance Standards (NSPS).

Table 3-1
U.S. Gasification and IGCC Demonstration History

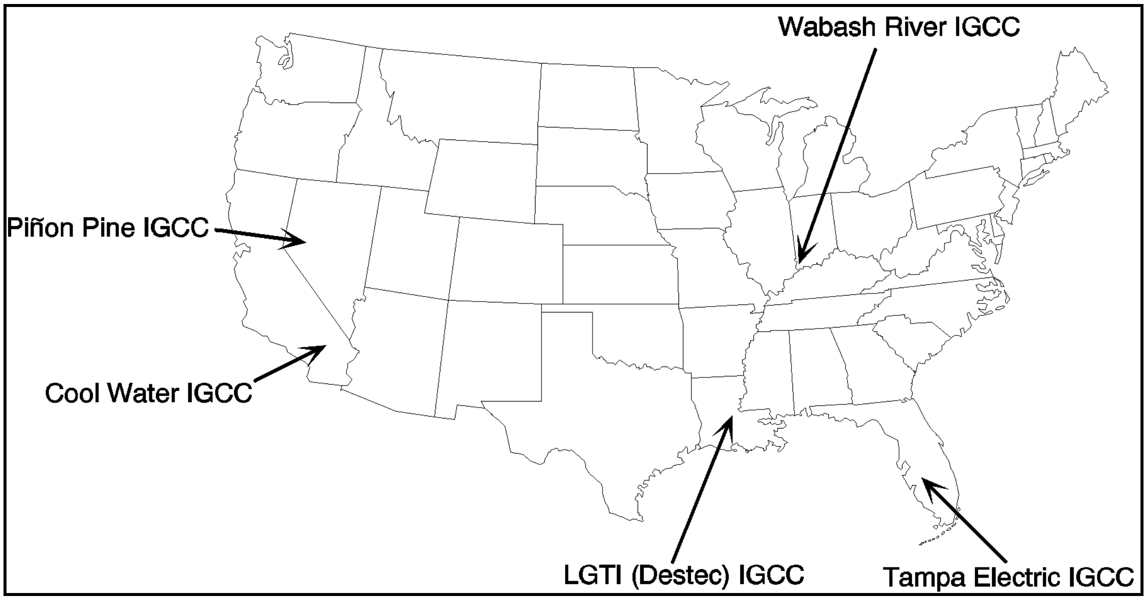
Plant	Location	Operation	Significance
Cool Water Existing CC Gasification	Daggett, CA	1984	1st U.S. commercial scale IGCC power plant
LGTI Partial Demonstration	Plaquemine, LA	1987	Dow Chemical commercial venture to exploit power generation growth opportunities
Wabash River CG Repowering	West Terre Haute, IN	1995	Demonstrate advances in entrained bed gasification while operating on high-sulfur coal at commercial size
Tampa Electric Greenfield	Lakeland, FL	1996	Demonstrate IGCC at 250 MW size with partial hot gas cleanup, ASU N_2 injection and NOx control
Piñon Pine IGCC Power Project	Reno, NV	1997	Demonstrate air-blown gasification with hot gas cleanup and low-Btu combustion turbine at commercial scale

Table 3-2
Progression of IGCC Cost‡ and Performance

Time Frame	Cool Water 1985	CCT 1995	DOE Goal 2000	DOE Goal 2010
Efficiency, HHV	32%	40%	42%	>50%
TPC,‡ 1990 \$'s	\$2,500/kW	\$1,500/kW		
TPC,+ 1999 \$'s	\$2,698/kW	\$1,615/kW	\$1,250/kW	\$1,000/kW
SO_2, lb/10^6 Btu	0.14	0.10	0.12*	0.12*
NOx, lb/10^6 Btu	0.07	0.16	0.06*	0.06*

\+ Overnight Total Plant Cost, 1995\$'s escalated based on Chemical Engineering Index.
* Based on 10% NSPS of 1.2 lb/10^6 Btu SO_2 and 0.60 lb/10^6 Btu NOx for high-sulfur coal.
‡ Adjusted to remove specific costs associated with demonstration projects.

Figure 3-2
Major U.S. IGCC Demonstration Locations



The basis for the DOE goals of increasing efficiency and lower costs is an IGCC commercial development program involving both government and industry R&D. This program targets development of IGCC components, concepts, and subsystems to proof-of-concept scale, resulting in demonstration in a stand-alone process or as a slipstream on a planned IGCC demonstration project. The DOE IGCC Program Plan is aimed at improving efficiency, cost optimization, and environmental stewardship through the following areas of technology development:

- Advanced gasifier concepts
- Advanced gas separation
- Hot particulate removal
- Hot gas desulfurization
- Trace contaminant control
- Sulfur recovery and other byproduct recovery processes
- Advanced turbine systems

The DOE goals for year 2000 of 45 percent efficiency and $1,200/kW (1990 $) are based on achieving published[3] goals associated with the IGCC Program Plan along a development timeline. Improvements in hot gas desulfurization and hot gas particulate removal are directed at lowering capital costs as well as increasing efficiency. These systems may differ from today's commercially available systems in that they may use hot gas cleanup at 800 to 1200 °F, with air-blown gasifiers. The achievement of these goals has been based on the projected success of the following testing and demonstrating facilities:

- Power Systems Development Facility (PSDF, Wilsonville, Alabama)
- Hot Gas Desulfurization Process Development Unit (HGD/PDU)
- GE Gasifier/HGCU pilot plant development

Wilsonville PSDF has initiated operation in a test mode, using the transport reactor. The transport reactor will be initially operated at the PSDF as a pressurized fluid-bed combustor to produce a flue gas for hot gas particulate filter experiments. The FETC HGD/PDU is under construction, and is scheduled for startup in 1999. The GE moving-bed pilot plant development at Schenectady, New York has been completed and the next phase of development is scheduled to be a slipstream demonstration at the Tampa Electric Company CCT project. Based on these adjusted schedules, it is probable that achievement of the hot gas desulfurization and hot gas particulate removal goals will demonstrate commercial viability after year 2000, missing the DOE goal. However, it is still possible to approach and even reach plant efficiencies of 45 percent through application of advanced gas turbine technology.

To achieve efficiencies of greater than 52 percent and costs less than $1,000/kW in 2008, the DOE goals are based on projected demonstration of an advanced gasifier and developing of an advanced turbine system. In view of the success of the CCT program and commercialization of gasifiers, the scope and development of advanced gasifiers have been scaled back, with little impact on the program goals. The M.W. Kellogg transport reactor has potential for evolving into an air-blown gasifier with in-situ desulfurization. This was shown in the DOE-FETC prepared conceptual design and cost estimate presented at the 11th Pittsburgh Coal Conference.(6) The gas turbine had a firing temperature of 2600 °F and a pressure ratio of 18:1. The HHV energy efficiency for the IGCC cases ranged from 52.1 to 52.8 percent, and the costs were reported to be 80 to 86 percent of a conventional fluidized-bed gasifier plant. Significant advancements in gas turbine technology have resulted in projections of high efficiency and high power output, providing additional confidence of reaching both the efficiency and capital cost goals.

Clean Coal Technology Demonstration Program

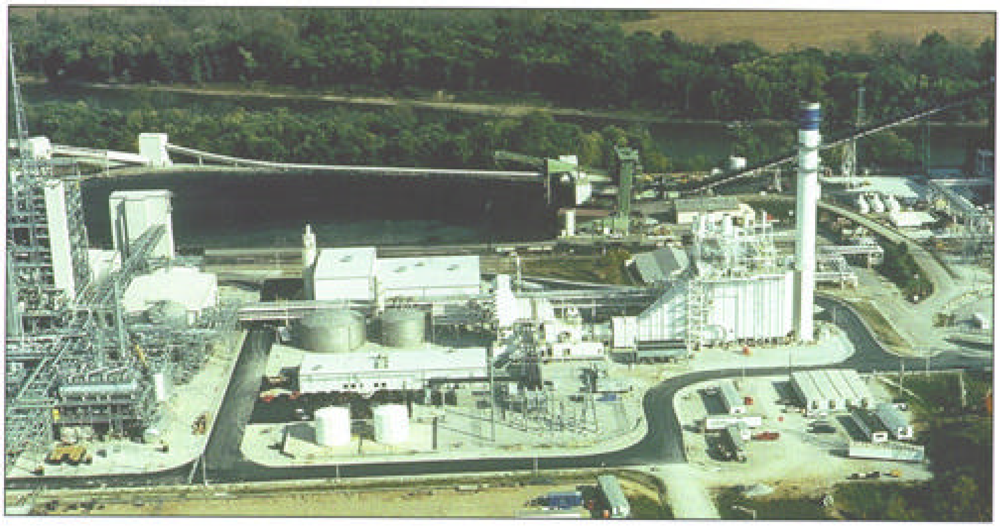
The cost and performance of CCT plants indicated in Table 3-2 are averages for the IGCC demonstration plants. The costs were adjusted to remove costs unique to the specific project; for example, the cost of additional testing and monitoring equipment characteristic of a demonstration project. This resulted in a capital cost in 1995 dollars for each CCT plant indicative of a plant that can be considered as the first commercial offering following the demonstration. Table 3-3 shows these values in a cost and performance summary of the CCT plants.

Table 3-3
Cost and Performance Design Summary of Clean Coal Technology Plants

	Wabash River	Piñon Pine	Tampa Electric
Plant Classification	Repowering	Brown Field	Green Field
Gasifier	Oxygen-Blown Entrained Bed	Air-Blown Fluid Bed	Oxygen-Blown Entrained Bed
Cleanup	Cold	Hot	Cold
Net Power, MW	252	100	250
Heat Rate, Btu/kWh	8,910	8,390	8,600
Efficiency, HHV	38.5%	40.7%	39.7%
SO_2 Emissions, lb/10^6 Btu	0.02	0.02	0.21
NOx Emissions, lb/10^6 Btu	0.08*	0.16	0.27
Capital Cost, $/kW (1995 $)	$1,450	$1,900	$1,600

Reference: Clean Coal Technology Topical Reports, U.S. DOE
*Existing permitted NOx level; operational data have demonstrated lower emissions.

Wabash. Each of the three CCT demonstration plants is unique in its selection of IGCC technology and its site-specific application of the technology. The Wabash River project is a repowering project utilizing the Destec (Dynegy) entrained flow oxygen-blown gasifier. The project utilizes the GE Frame 7F turbine to repower one of six units at PSI Energy, Inc. (PSI) Wabash River Generating Station and produce a net electrical power of 252 MW. The project utilizes a cold cleanup process resulting in plant SO_2 emissions of only 0.02 lb/10^6 Btu. The Destec gasifier was fired with coal in August 1995, and the gas turbine was fired with fuel gas in October 1995. Since 1996, the gasifier accumulated over 9,000 hours of operation on coal, and the combined cycle operated over 8,000 hours on syngas. (See Figure 3-3.)



Wabash IGCC power plant. The Destec Gasifier structure, gas cleanup system, and sulfur recovery plant are on the left. Gas turbine auxiliary fuel tanks are in the center. Right center is the GE MS 7001FA gas turbine and HRSG. The pipe rack exiting the HRSG passes under the bridge to the building containing the repowered steam turbine.

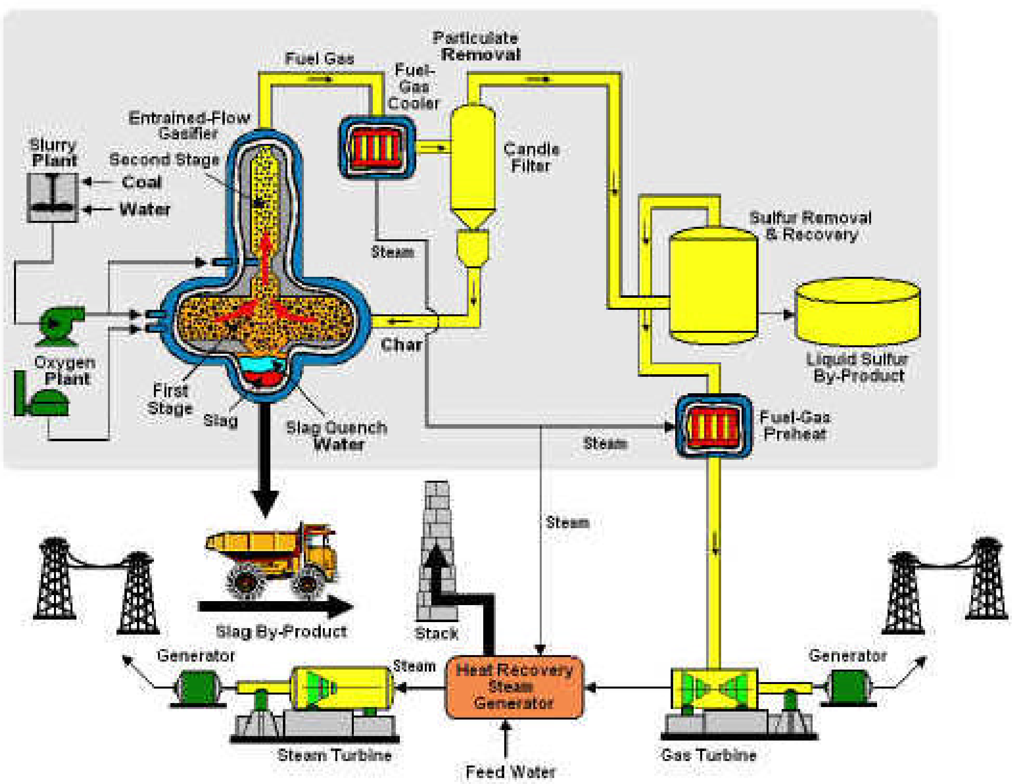
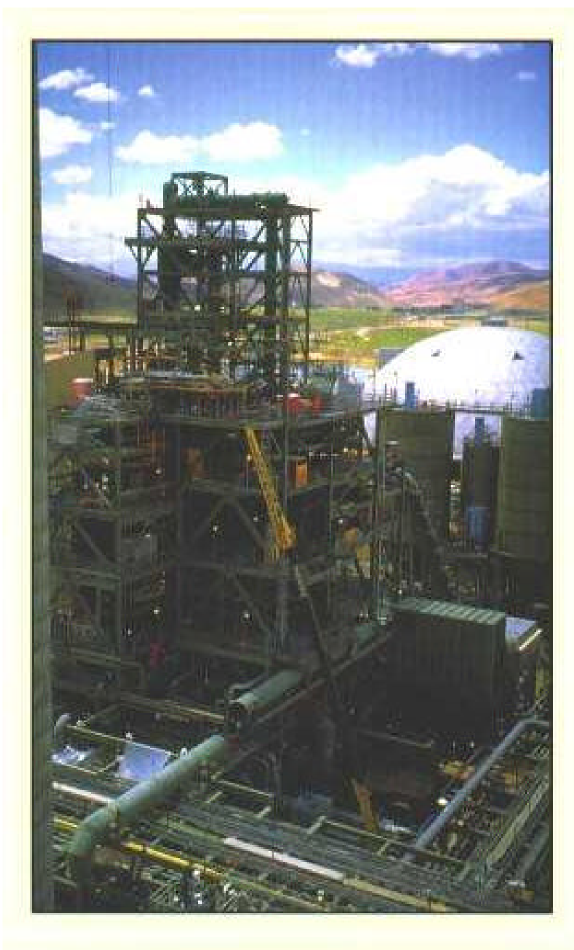


Figure 3-3
Wabash Flow Schematic

Piñon Pine. The Piñon Pine project is classified as a brown field project in that the site is located at the Tracy Station of Sierra Pacific Power Company and utilizes available onsite facilities, but is not integrated with the existing station. The Piñon Pine project features the KRW fluidized-bed air-blown gasifier. The process includes in-bed desulfurization with limestone to remove about 50 percent of the H_2S, followed by a hot gas desulfurization polisher. The polisher is a transport reactor configuration utilizing a zinc-based regenerable sorbent. Regeneration gas and gasifier LASH (limestone/ash) are sulfated to disposable calcium sulfate. SO_2 emissions from this project are exceptionally low, 0.02 lb/10^6 Btu, which reflects the anticipated performance of the combination gasifier and hot gas polisher utilizing the zinc-based sorbent. A Westinghouse ceramic filter is utilized to ensure that the hot gas is particulate-free prior to combustion in a GE Model 6FA turbine, which produces net 100 MW in a combined cycle mode. The Piñon Pine project was commissioned in 1996, and moved into final commissioning and startup mode in February 1997 using coke breeze and Utah coal. The plant continues to operate with natural gas while resolving problems preventing fully integrated operation. (See Figure 3-4.)



Easterly view of site area during construction of Piñon Pine. The gasifier structure is to the left and the raw coal storage dome is on the right. I-80 is in the background.

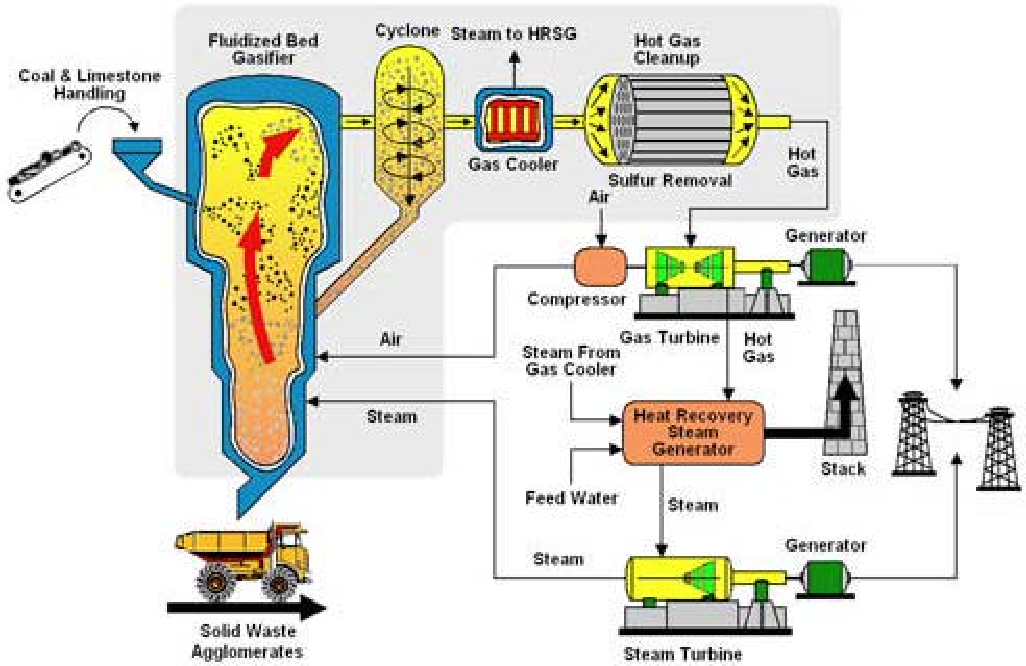


Figure 3-4
Piñon Pine Schematic

Tampa. The Tampa Electric Company Polk Station project is a green field project based on the Texaco entrained flow oxygen-blown gasifier. The project is located in Polk County, Florida on a former potash mining site. The project utilizes a GE Frame 7F gas turbine operating in a combined cycle mode to produce a net power output from the plant of 250 MW. The project used a cold gas cleanup process for sulfur removal, with sulfur recovery as sulfuric acid. Provisions are in place to demonstrate a GE hot gas moving-bed desulfurization process from a slipstream, with the regeneration gas being sent to the sulfuric acid plant. Particulate cleanup of gas following the GE moving-bed will be achieved with a Pall sintered stainless filter. Permitting limits the Tampa SO_2 emissions to 0.17 lb/10^6 Btu after two years of demonstration. Lower emissions are projected with the technology in place. The Tampa project began operation in July 1996, and operated commercially in the test phase in 1997. (See Figure 3-5.)

The Texaco gasifier is in the largest structure, which also contains the radiant syngas cooler. The hot gas cleanup system is installed in the smaller of the two large structures. In the foreground is the air separation unit.

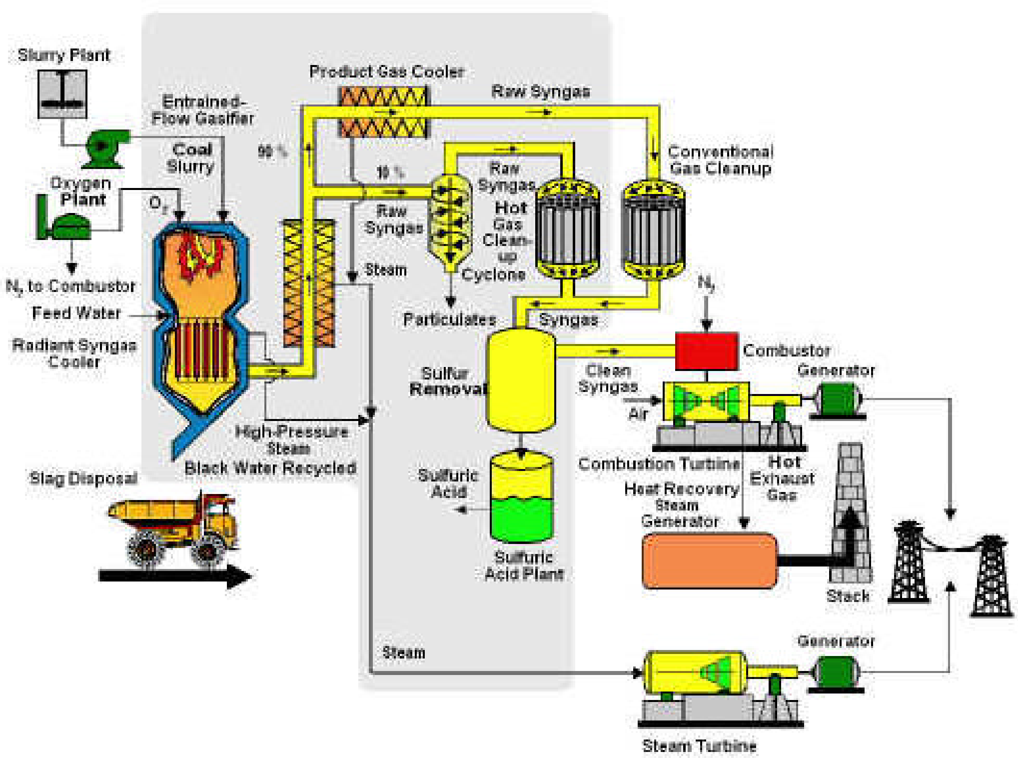


Figure 3-5
Polk Station Flow Schematic

The CCT IGCC projects described in this report are representative of the type of plant that can be designed and constructed around a gasification process, and they provide a source of operating experience that can minimize perceptions of risk for future plants. The emissions from an IGCC plant are significantly lower than from other coal-based plants. This is primarily due to the removal of sulfur and nitrogen as intermediates rather than as oxidized compounds, development of gasifiers that have essentially 100 percent carbon conversion, and the use of low-NOx burners and peak flame temperature control in advanced gas turbines.

Gas Turbines. Development of advanced gas turbines continues to be supported by the DOE.

Recently, GE announced that it will offer the Frame 7H gas turbine, which fires at 2600 °F. The "H" turbine will produce 460 MW in a combined cycle with an efficiency of 60 percent LHV (54 percent HHV) on natural gas. In an IGCC, energy efficiency is expected to be about 45% HHV. Siemens-Westinghouse announced its initial sale of the W501G in mid-1997. With the availability of these advanced turbines (see Figure 3-6), the capital and operating cost of IGCC systems is projected to be less than that of a conventional PC plant with flue gas desulfurization (FGD) as shown in Figure 3-7. This figure illustrates that due to increases in efficiency for combined cycles, IGCC is in a competitive position with conventional coal plants. With IGCC plant costs coupled to gas turbine improvements, it is estimated that "F" technology gas turbines can bring IGCC capital costs within 10 percent of a PC plant with FGD, and "H" technology gas turbines can achieve competitive costs.

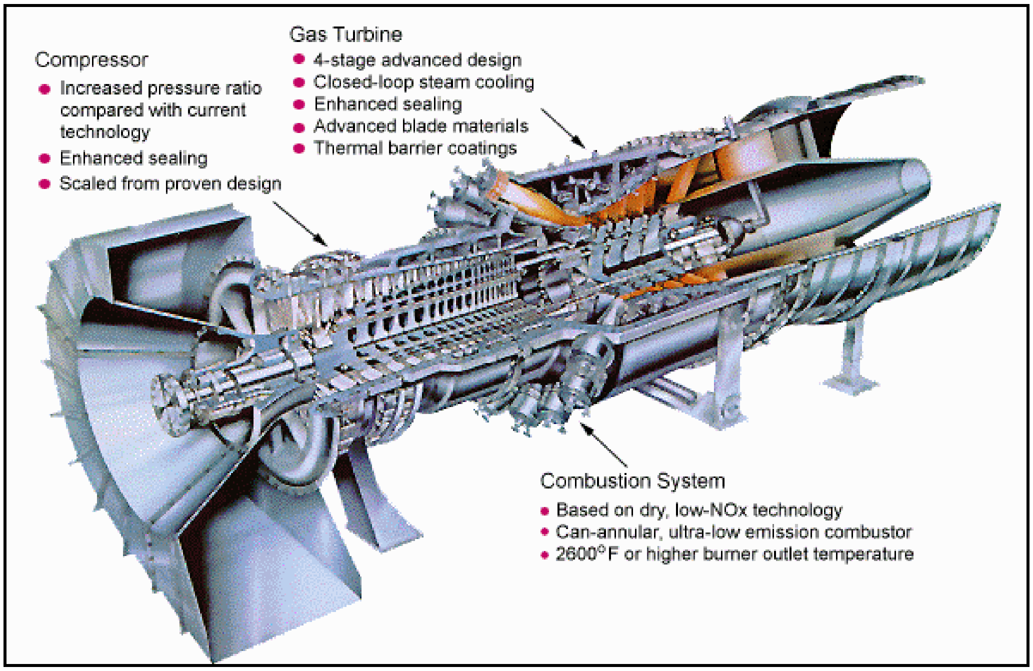


Figure 3-6
Representative ATS Turbine

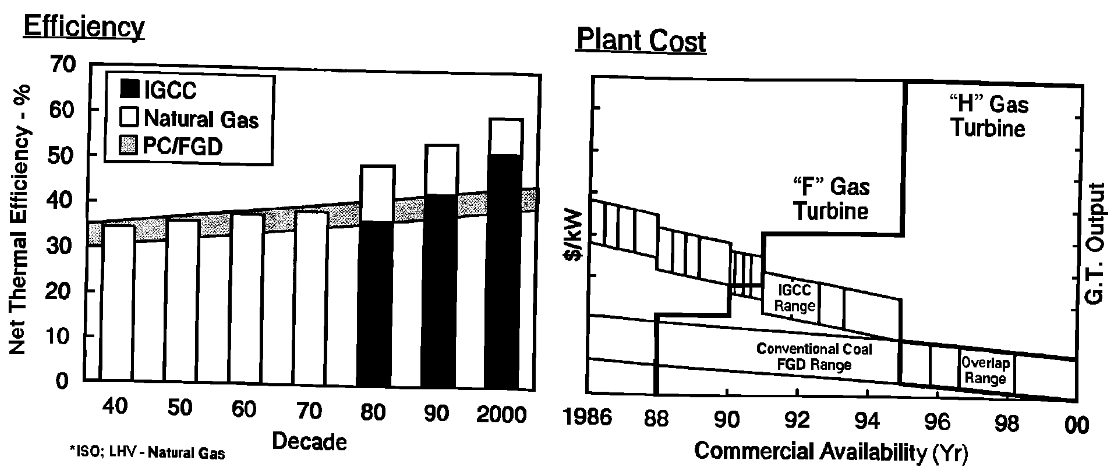


Figure 3-7
Gas Turbine Development Impact on IGCC Capital Costs
(Source: General Electric, EPRI Conference on New Generation Technologies, 1995)

Design Flexibility. A unique feature of IGCC plant design is that flexibility exists in process selection so that it is possible to combine both advanced technology and commercially available technology together in the same plant to meet the needs of the specific project. This approach is demonstrated in plants of the CCT program in which gasifiers, cleanup processes, and power systems from various stages of development are integrated to achieve commercial operation with the minimum operational risk in a unit that is built today. Rather than use one of the CCT demonstration plant designs to directly compare IGCC with available conventional power producing technologies, the IGCC plant concepts in this document evaluates two CCT gasifiers (the KRW and Destec) in conjunction with the probable commercially available hot gas cleanup and gas turbine in 2005. The anticipated success of the CCT program, the development of commercial process equipment, and the advancement of gas turbines provide an impetus for the comparison of IGCC with conventional technologies.

Commercial Interest in IGCC. In addition to the IGCC technology advances for power generation through successful CCT demonstration plants, the gasification and power-producing technology has also progressed in other markets. There is a worldwide interest in gasification-based power and coproduction projects, due primarily to the environmental advantages that gasifiers display in conversion of low-quality dirty fuels into clean syngas.

Nowhere is this more evident than in the use of IGCC technology for refinery-based applications. Recently, oil refineries have been driven to accept heavier crudes as feedstocks, resulting in additional residual oil and increased petroleum coke production. The solid and liquid refinery "bottoms," contaminated with sulfur and heavy metals, are ideal low-cost feedstocks for IGCC technology. Also, expanded refinery capability results in a need for hydrogen, steam, and on-site power. Both power-based IGCC and refinery-based IGCC have common systems that aid the transition from power to refinery applications. These include the gasifier and its feed system, the gas cleanup process, and power generation. Whereas the power-based IGCC is bounded by the requirement to produce and distribute power, and its feedstock is generally coal, the refinery-based application can also be used to generate steam and syngas for hydrogen or chemicals, in addition to power. As a result, the refinery-based IGCC has the flexibility to consider many options that improve the overall economics.

Because of this interest and potential for wide-scale commercialization, industrial partners and other developers are on track in their development of commercial products. The gasifier with the greatest experience base for both syngas and power production is the Texaco Gasification Process (TGP). The TGP has been used in more than 100 commercial facilities to manufacture syngas over a span of more than 40 years. Texaco has been active in China, where more than 10 chemical plants are now operating, producing gas, ammonia, and co-chemicals from coal and residual oils. Texaco reached an agreement with the China Ministry of Chemical Industry/Sinopec to license an additional nine plants to produce ammonia from coal, having startups from 1998 through 2004.

Outreach. The gasifier and turbine technology advancements are freely published in numerous meetings throughout the year. The most comprehensive meeting for these technologies is the annual Gasification Technologies Conference held in San Francisco, sponsored by EPRI and the Gasification Technologies Council.

The CCT program provides a public forum from which numerous reports are available regarding both the overall CCT activity and individual projects. These are a valuable base of information for engineers throughout the world. DOE publishes the Annual Program Update for the CCT demonstration program. Additionally, each project publishes special reports including:

- Comprehensive Report to Congress
- Topical Report on Project Status
- Public Design Report (Final)
- Technical Progress Reports (Quarterly)
- Demonstration Technology Startup Report
- Final Report

IGCC operating costs can be lower than those of a PC plant due to reduced fuel use from its low heat rate, byproduct sulfur credits, and low volume of solid waste. Other potential economic advantages of IGCC may be achieved through phased construction, coproduction of marketable byproducts, fuel flexibility, and use of low valued feedstocks such as petroleum cake.

3.1.1.1 Phased Construction

Phased capacity addition or phased construction is the addition of modules of power generation capacity with short lead times. Initial operation uses a quickly constructed conventional gas turbine operating on natural gas; this generates a revenue source from the production of electrical power early in the project. The final operation of phased construction replaces the natural gas with coal gasification as the fuel feed, taking advantage of the lower price of coal. As natural gas consumption in electric generation increases, natural gas supplies and prices relative to the price of coal become important long-term issues. Through the use of CCT, power companies can use IGCC to replace natural gas when that proves economically advantageous.

3.1.1.2 Coproduction

Gasification technology does not have to be limited to the production of fuel gas for firing gas turbines in a "power only" application. Gasification of carbon-based feedstocks can also be attractive for producing other valuable products, such as syngas, carbon monoxide, hydrogen, and steam. Adjustments in the process allow the production of a range of operating volumes and hydrogen/carbon monoxide molar ratios. Products that result from partially oxidizing hydrocarbon feedstocks are the basic raw materials for the synthesis of many fuels, petrochemicals, and agricultural chemicals. Stand-alone gasification plants have been operating for years with refinery waste streams to produce syngas for chemical production. Various options for downstream integration correspond to a range of value-added products, i.e., electricity, steam, hydrogen, and commodity chemicals.

Syngas from a gasifier must often compete with alternative natural gas. The decision is driven by the relative price of the gasifier feedstock (coal or other carbon-based feedstock) and natural gas. In the case of combined power production, natural gas would be fed directly to the gas turbine. The gasifier feedstock must be sufficiently low-priced so that the overall IGCC can economically compete with a natural gas-fired combined cycle plant of the same size. However, if the desired end-product requires CO and hydrogen as an intermediate, natural gas must be steam reformed to produce an equivalent mixture. The natural gas option then carries a capital cost and conversion efficiency burden, which improves the competitive position of gasification-derived syngas.

An example of producing chemicals from coal is the CCT Eastman Chemical facility in Kingsport, Tennessee, which converts coal-derived syngas to methanol and CO. These are reacted with other chemicals to eventually produce cellulose acetate. The Ruhrchemie AG plant in Germany produces oxo-chemicals from syngas, and operating plants in India, Japan, and China produce ammonia from coal. The Sasol complexes in South Africa include nearly 100 Lurgi gasifiers producing a wide variety of chemicals and liquid fuels.

3.1.1.3 IGCC Fuel Flexibility

The design basis for evaluation of IGCC processes often assumes the use of a high-sulfur bituminous coal delivered from midwest U.S. mines. Although this coal is the most common feed used for evaluations, alternate feedstocks have been evaluated and studied for gasifier applications. In addition to different coals, other carbon-based feeds and biomass fuels have been considered as an alternative fuel source.

Carbon-Based Feeds. Since August 1995, the Destec gasifier at the Wabash River plant has been operating on high-sulfur bituminous coal. Prior to that, the Destec gasifier at Plaquemine, Louisiana operated in a demonstration mode on a wide variety of coals, which included lignite and subbituminous coal, as well as bituminous coal. Texaco's slurry-feed gasifier was originally designed for partial oxidation of heavy residuals from refinery bottoms, and evolved into a commercial gasifier of solids that are fed by a slurry. The Texaco gasifier is capable of gasifying all coals as well as petroleum coke and Orimulsion®, a proprietary emulsion formed from water and bitumen.

Biomass. Oxygen-blown gasifiers, which rely on hot firing of the reactant to slag the ash, cannot achieve the high temperatures with the lower quality fuels such as biomass, primarily due to the high water content in the fuel. Air-blown fluid-bed gasifiers such as the Battelle Columbus indirect gasifier, U-Gas, and the KRW, which operate at a lower temperature, have been operated at pilot scale on biomass.

Biomass is a fuel of increasing interest because it is classified as a clean and renewable fuel. Wood is of special interest in the Nordic countries. Tampa Power, Inc. and Vattenfall AB made a joint effort to develop a biomass-fueled IGCC system utilizing a fluid-bed gasifier. Enviropower's 15 MWth pilot plant in Tampere, Finland was the site for the research program in which 3,000 tons of wood residue was gasified.

The RENUGAS process was developed for pressurized fluid-bed gasification of biomass to produce either fuel gas or syngas, depending on operation in an air- or oxygen-blown mode. The 12 ton/day single-stage reactor for the process development unit (PDU) was built at the Institute of Gas Technology (IGT) under a DOE program, and has been tested under various operating conditions with feedstocks varying from refuse-derived fuel (RDF) to herbaceous biomass.

Feed Flexibility. A wide range of fuel types and properties can be gasified. For each application, the fuel choice should be based on plant and feedstock location, transportation and supply costs, long-term availability and security of supply, and guaranteed performance in a gasifier of choice. Some gasifier designs are superior for specific types of feedstock; almost all are suited to coal feedstocks.

3.1.1.4 Marketable Byproducts

The primary marketable byproducts from IGCC plants are sulfur-based, and are in the form of elemental sulfur, sulfuric acid, or gypsum. Sulfur is a chemical element that is stable in its native, or elemental state.

Elemental Sulfur. In the United States, elemental sulfur is the dominant form of sulfur supply. The domestic market for elemental sulfur (10,811,000 tons shipped in 1988) is available in two basic forms: Frasch sulfur and recovered sulfur. The overall sulfur supply can be divided into two major pools: one that feeds into manufacturing of sulfuric acid and the other to non-sulfuric-acid end users. Statistics indicate that the combined inventories of elemental sulfur are surprisingly small compared to the size of the consumption pools. In 1988, the year-end stocks amounted to only a 1.2-month supply relative to the rate of domestic consumption and export of elemental sulfur. Molten sulfur and sulfuric acid are often delivered in a "just-in-time" fashion to end users to minimize storage costs at the end-user locations.

Sulfuric Acid. Next to elemental sulfur, the second basic form of sulfur supply in the United States is sulfuric acid (H_2SO_4), which consists of byproduct and reclaimed sulfuric acid. The so-called byproduct sulfuric acid is also a non-discretionary byproduct from copper/zinc/lead roasters and smelters, which invariably produce sulfur dioxide (SO_2) in gaseous form.

The single, overwhelming end user of sulfuric acid is the phosphatic fertilizer industry, which consumed 8,404,000 tons of equivalent sulfur per year. This is more than two-thirds of the total sulfuric acid produced/reclaimed in the United States at 12,334,000 tons of equivalent sulfur.

The primary function of sulfuric acid is to digest and decompose phosphate rock, and to capture the excess calcium in the form of gypsum ($CaSO_4 \cdot 2H_2O$). The end result is that the solid mixture of mono-calcium phosphate and gypsum (commonly called single superphosphate) is rendered more water soluble than the original phosphate rock. When the mixed fertilizer is applied to the soil, sulfur in gypsum is ultimately returned to the earth to complete the earth-to-earth sulfur cycle.

It is interesting to note that, regardless of whether the sulfur was originally in acidic form or elemental, major end users of sulfur are the phosphatic fertilizer and its allied agricultural chemicals sectors.

All forms of sulfur tend to metamorphose into sulfuric acid (H_2SO_4) and, eventually, to calcium sulfate ($CaSO_4$), whether it was originally in a reduced form (e.g., hydrogen sulfide, H_2S, from a petroleum refinery), neutral state (e.g., freshly mined Frasch sulfur, S), or an oxidized form (e.g., sulfur dioxide, SO_2, from a smelter). The current industry practice of sulfur handling (i.e., H_2S is oxidized to yield neutral elemental sulfur and SO_2 is oxidized to yield H_2SO_4 but not reduced to elemental sulfur) appears to be consistent with the thermodynamic trend of oxidation of products.

The Market for Sulfur. The sulfur-sulfuric acid market appears to have been level for the past year or two. Recent (1999) quotations from the Chemical Market Reporter indicated the following prices, which have been relatively consistent for more than one year:

C	Frash sulfur, New Orleans	\$54/long ton
C	Recovered sulfur, Houston	\$47/long ton
C	Sulfuric acid, Gulf Coast	\$75/short ton

In summary, the most significant finding is that (1) all sulfur tends to transform into sulfuric acid, and eventually into $CaSO_4$, and that (2) the elemental sulfur tends to stay in its form for only a month or two. All of this indicates that the decision to make elemental sulfur or H_2SO_4 from a non-discretionary sulfur source is purely site-specific, and is at the discretion of the owner.

3.1.1.5 Low-Price Feedstocks

When the opportunity exists, gasifiers can be used to financial advantage when there is a low-priced feedstock available. Several refinery-oriented IGCCs, either operating or under construction, produce energy and/or chemicals from waste or low-priced feedstock streams. Texaco's refinery at El Dorado, Kansas utilizes coke gasification to power a GE 6000B 40 MW system to produce power and coproduct steam. Star Enterprises Delaware City refinery will gasify 2,200 tons per day of fluid petroleum coke to produce 200 MW and steam. The Shell Pernis refinery in the Netherlands will gasify residuals to produce 113 MW, steam, and hydrogen. The trend in refinery integration is to produce syngas with the flexibility to produce either power or hydrogen, depending on the current or future operational strategy. This type of gasifier application indicates a trend toward tri-generation of power, steam, and syngas products within refineries as an efficient solution to low-value, high-sulfur fuel utilization.

3.1.2 Pressurized Fluidized-Bed Combustion (PFBC)

Two categories of PFBC plants, referred to as first-generation and advanced PFBC systems, characterize this clean coal technology power generation option. Each system has unique design and operating features, and both achieve higher efficiencies by combining gas and steam turbines in the generating cycle. In the first-generation systems, coal is burned under pressure in a PFBC vessel containing steam generating tube surfaces. The hot pressurized gas is expanded through a gas expander; the steam raised in the PFBC boiler is used to drive a conventional steam turbine. A sorbent, such as limestone, is fed with the coal in the fluid bed to absorb sulfur. In the advanced systems, the coal is pyrolyzed under pressure to produce a fuel gas for a gas turbine, and the residual char is burned in a PFBC to generate steam for the combined cycle.

3.1.2.1 First-Generation PFBC Systems

In first-generation PFBC units, shown conceptually in Figure 3-8, compressed air is supplied to a fluidized combustor/boiler, and the coal is burned under pressure. Particulates are removed from the flue gas with cyclones and/or hot gas filters. The flue gas then passes through an unfired gas turbine that drives a generator and an air compressor. The gas turbine produces about 20 percent of the net output. High-pressure steam is raised in tubes positioned in the PFBC boiler, and the steam turbine generates approximately 80 percent of the net power output. Limestone is fed to the PFBC boiler to capture sulfur released from the coal during combustion. The boiler can be either a bubbling or a circulating fluidized bed.

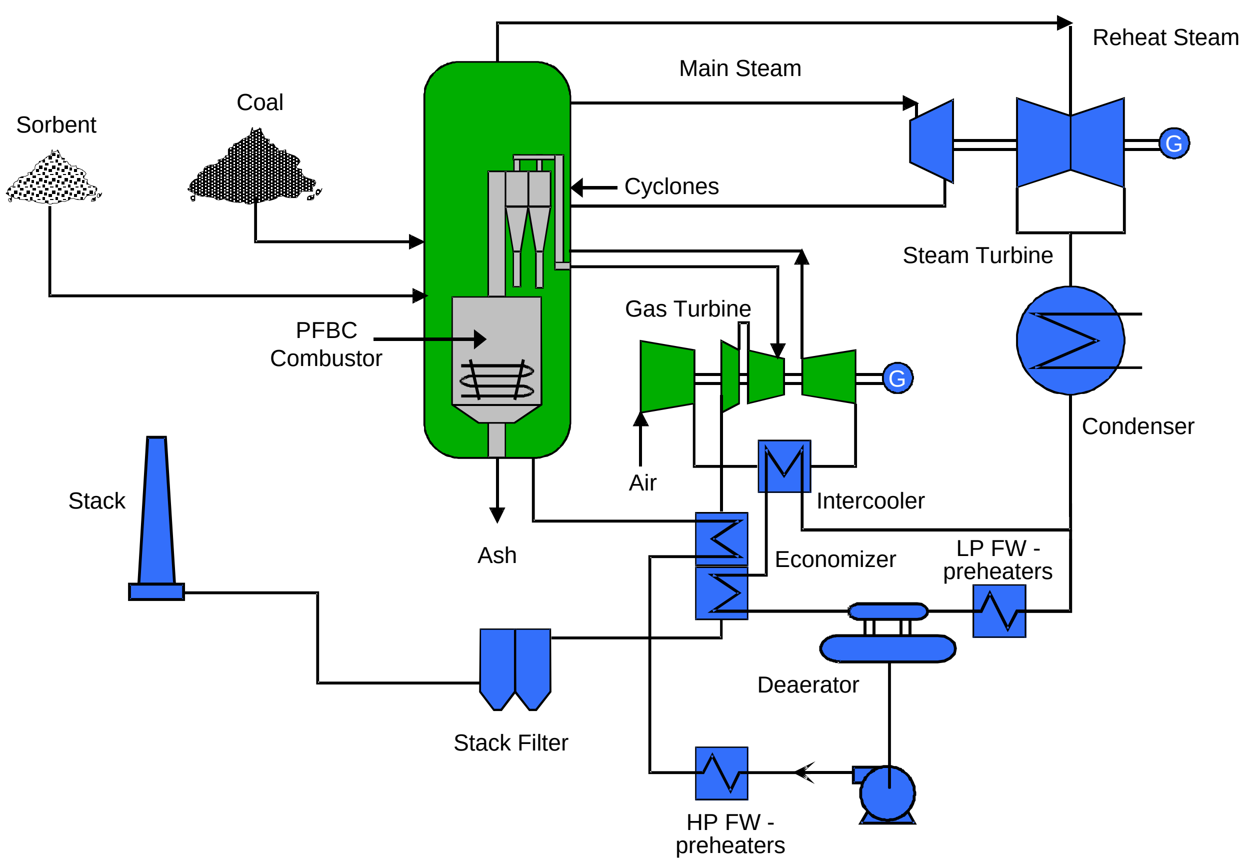


Figure 3-8
Bubbling Bed PFBC

Bubbling PFBC

In the period 1989 to 1993, several combined-cycle bubbling PFBC demonstration units commenced operation, as indicated in Table 3-4. These led to a number of commercial PFBC plants that are described in the discussions that follow. The commercial units have nominal outputs of 80 MW and larger and are located in Spain, the United States, Japan, Germany, and Sweden. The plants burn high- and low-sulfur bituminous coal and lignite, with environmental performance that has proven better than expected based on results from small-scale testing. Operating experience has identified a number of ways to simplify design and lower capital cost of future units.(7) Three additional units will become operational in the near-term, 1999. All the units are designed using ABB Carbon technology.

Table 3-4
PFBC Commercial Plants Overview

Plant	Type	Size	Location	Vendor	Status
Värtan	Bubbling Bed (two units)	135 MWe +225 MWth	Sweden	ABB Carbon	Operational 1989
Escatron	Bubbling Bed	75 MWe	Spain	ABB Carbon	Demo operational 1990
Tidd	Bubbling Bed	70 MWe	U.S.	B&W under license from ABB Carbon	Testing completed Shut down
Wakamatsu	Bubbling Bed	70 MWe	Japan	IHI under license from ABB Carbon	Operational 1994
Karita	Bubbling Bed	360 MWe	Japan	Hitachi	Progressing into operational phase
Cottbus	Bubbling Bed	74 MWe +220 MWth	Germany	ABB Carbon	Progressing into operational phase
Osaki	Bubbling Bed	250 MWe	Japan	Hitachi	Progressing into operational phase
Chugoku	Bubbling Bed	2 x 250 MW	Japan	Hitachi	Operational 1999
Tomatoh	Bubbling Bed	85 MW	Japan	MHI	Operational 1995

References 10 through 19 provide details on these facilities.

PFBC Commercial Plant Descriptions

The Tidd CCT demonstration plant is representative of a commercial first-generation PFBC power generation station, designated as a P-200 PFBC. The plant used an ASEA Stal GT-35P gas turbine operating in a combined-cycle mode to produce a net power output from the plant of 70 MWe. The project used a limestone or dolomite sorbent for sulfur control and cyclones and an ESP downstream of the gas turbine for particulate control. A low bed temperature of 1600 ºF limits NOx formation.

Table 3-5 indicates the cost (Ref. EPRI TAG, 1993[8]) and performance characteristics[9] of a first demonstration-scale plant based on the Tidd plant.

Table 3-5
P-200 PFBC Plant Characteristics

	Commercial Plant
Net Power Output	70 MWe
Plant Efficiency, HHV	35.0%
SO_2 Emissions	95% removal
NOx Emissions	0.30 lb/10^6 Btu
Particulates	0.02 lb/10^6 Btu
CO_2 Emissions	N/A*
Total Plant Cost, 1997 $	$1,943/kW

*Not available

The Karita plant, due in operation in 1999, is a scaled up version of the Tidd plant and is representative of the next generation in bubbling PFBC plant design, designated as P-800 PFBC. The plant utilizes a ASEA Stal GT-140P gas turbine operating in a combined-cycle mode to produce a net power output from the plant of 360 MWe. Limestone or dolomite sorbent is used for sulfur control and cyclones and an ESP downstream of the gas turbine for particulate control. A low bed temperature of 1600 ºF limits NOx formation. Table 3-6 indicates the cost (Ref. EPRI TAG, 1993[8]) and performance characteristics [10] of a commercial-scale plant.

The 70 MWe Ohio Power Company Tidd PFBC Clean Coal Technology first-generation bubbling bed PFBC plant in Brilliant, Ohio demonstrated feasibility of high-temperature particulate removal integrated with combustion turbine operation.

Tidd Plant, Ohio
Source: ©ABB Carbon [10]
9616EJ-tidd

Table 3-6
P-800 PFBC Plant Characteristics

	Commercial Plant
Net Power Output	360 MW
Plant Efficiency, HHV	42.0%
SO_2 Emissions	0.16 lb/10^6 Btu
NOx Emissions	0.10 lb/10^6 Btu
Particulates	0.01 lb/10^6 Btu
CO_2 Emissions	N/A
Total Plant Cost, 1997 $	$1,263/kW
Cost of Electricity	4.52 cents/kWh

Kyushu Electric's 360 MWe Karita, Japan PFBC plant, a first-generation 1xP800 ABB/IHI PFBC plant.(10)

Descriptions of other commercial PFBC installations listed in Table 3-4 follow:

The Electric Power Development Company's (EPDC) 70 MWe Wakamatsu, Japan, designed for hot gas filter tests with a first-generation 1xP200 ABB/IHI PFBC demonstration plant. The plant has ceramic tube filters, which by May 1997 had accumulated 2,600 hours of operation, and an additional 2,600 hours with a two-stage cyclone. A total of 10,000 hours of testing planned.[10,11,12,13]

Wakamatsu PFBC plant, Japan.
Source: ©ABB Carbon [10] 9616EJ-waka

Mitsubishi Heavy Industries, Ltd. built the 85 MWe output Tomatoh-Atsuma PFBC Unit No. 3.[16] *Unit 3 began trial operations May 1995, and entered commercial service on March 9, 1998 for the Hokkaido Electric Power Company, becoming the first commercial PFBC combined cycle in Japan. The 85 MW total output system uses an 11.1 MW gas turbine (MW-151P), and a 73.9 MW 2400 psi/1050 °F/1000 °F steam turbine. The system employs a cyclone and high-temperature ceramic tubular filters operating at 1560 °F to protect the gas turbine. It has an SCR for NOx reduction. As of January 1998, 6,048 hours of power operation were accumulated.*[17,18]

Tomatoh-Atsuma PFBC plant, Hokkaido Island, Japan.
Photo courtesy of Mitsubishi Heavy Industries Ltd.

74 MWe Cottbus, Germany is an ABB first-generation 1xP200 PFBC combustor. This will be an early commercial implementation of first-generation PFBC technology when it enters initial operation. The project is owned by Stadtwerke Cottubus (SWC) and the Hamburger Kommunalfinanzgruppe (KFG). The unit is lignite-fueled, and provides steam and hot water district heating (a total of 220 MWth for both) and 74 MWe electric output.[10,14,15]

Circulating PFBC

In 1990 to 1991, two boiler manufacturers, Pyropower and Deutsche-Babcock, commenced pilot plant studies to investigate circulating PFBC technology. These units operate at similar pressures but higher fluidizing velocities than the bubbling version (15 fps compared to 3 fps). This allows for a more compact design, modular construction, and shop assembly with correspondingly lower capital costs. The containing pressure vessel will have a smaller diameter than that of the bubbling version, although it is expected to be slightly taller. As the boiler is smaller, enhanced coal and sorbent distribution will be achieved with fewer feed nozzles. Heat rates are expected to be similar to those achieved by the bubbling version.

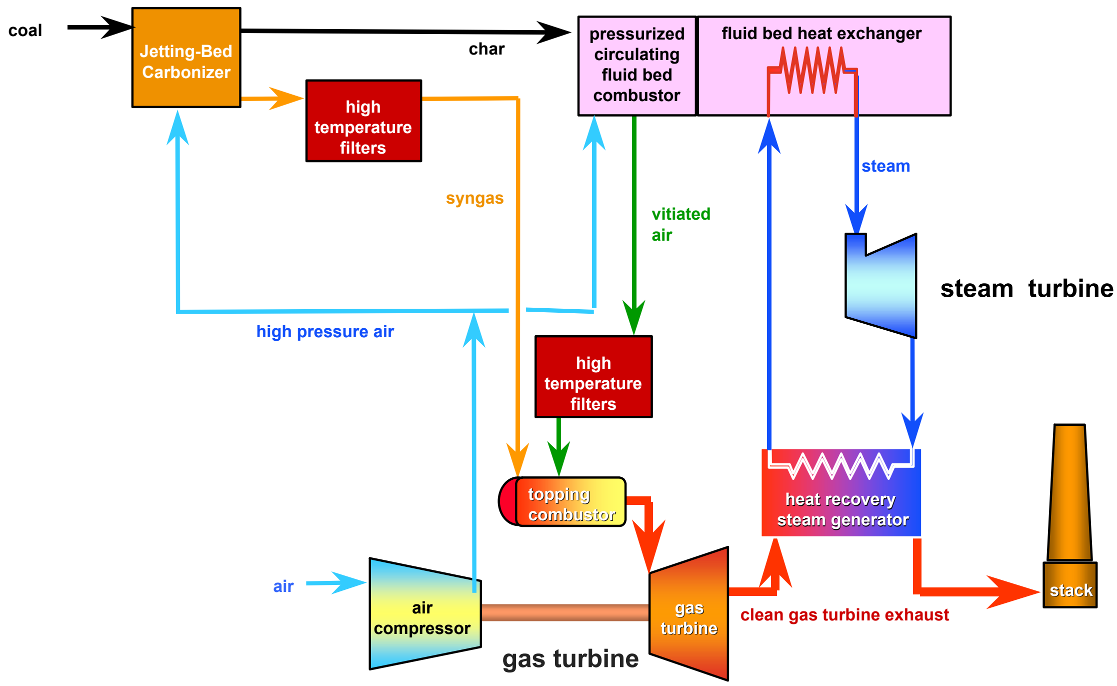
A high-temperature, high-pressure (HTHP) filter is used to clean the gas prior to entering the gas turbine. As the resulting flue gas contains very little dust, it allows conventional non-ruggedized gas turbines to be used. Moreover, it offers the additional economic benefit of allowing dust emission regulations to be met without back-end baghouse or electrostatic precipitator (ESP) equipment.

3.1.2.2 Advanced APFBC Systems

For the first-generation PFBC plant, the gas turbine inlet temperature is fixed by the PFBC combustor operating temperature of 1550 ºF to 1650 ºF, which limits overall cycle efficiency. By raising the combustion turbine inlet temperature, cycle efficiency can be raised substantially. Advanced PFBC (APFBC), or second-generation, designs improve upon the performance of a PFBC design by adding high-temperature gas turbine capability. Advanced PFBCs, shown in Figure 3-9, are under development by a team of companies led by Foster Wheeler Development Corporation, Siemens Westinghouse Electric Corporation, and DOE. Here, some of the coal energy is released in the form of a hot 1400 ºF combustible carbonizer off-gas, or syngas. The carbonizer, a jetting-bed device, acts as a mild gasifier. The hot low-Btu off-gas is cleaned of particulates and used as fuel in a special topping combustor that supplies the gas turbine with its full firing temperature and high efficiency. The char residue from the carbonizer contains some of the remaining coal energy, and is sent to a PFBC combustor. The PFBC completes the combustion with excess air. Since this vitiated exhaust air contains about 17 percent oxygen, it can support combustion of the carbonizer off-gas in the topping combustor. This vitiated air is also fed hot, 1400 ºF or hotter, to the topping combustor. To avoid ash sintering problems, it is necessary to filter both the syngas and the vitiated air to remove all particulate matter prior to firing. The PFBC combustor supplying the pressurized vitiated air could be either a bubbling or circulating coal-fired PFBC.

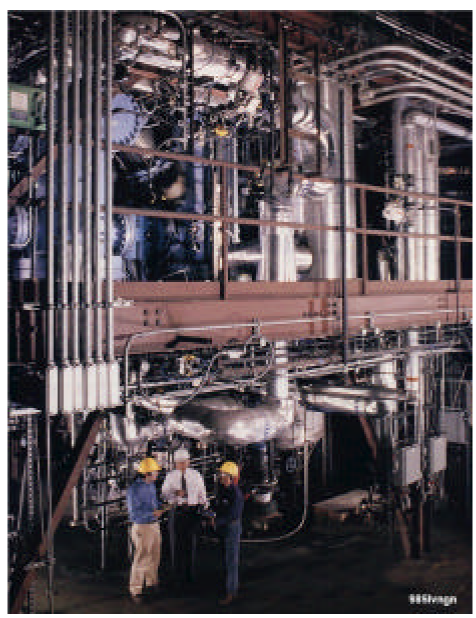
Figure 3-9

Second-Generation Advanced PFBC Process Diagram



APFB Research and Demonstration Facility Descriptions

The 1.1 MWe (equivalent capacity) integrated APFBC pilot plant at Foster Wheeler's Livingston, New Jersey facility demonstrated integrated operation of a pressurized carbonizer and circulating PFBC/fluid-bed heat exchanger (FBHE) system, including high-temperature candle filters operating at reducing and oxidizing conditions. The carbonizer operates at about 14 atmospheres and 1600 °F, and the PFBC operates at about the same conditions. The carbonizer and PFBC were tested individually, and in a 7-day test of integrated operation. These tests quantified system chemistry including the verification of sulfur capture with a calcium-based sorbent.[20]



Integrated PFBC test facility at John Blizzard Research Center
photo courtesy of Foster Wheeler

The 4 MWth EBARA Corp. pressurized internally circulating fluidized-bed boiler (PICFB) hot model test facility was developed with support from the Japanese Ministry of International Trade and Industry (MITI) and the Center for Coal Utilization Japan (CCUJ). The hot model test operates at about 215 psig (1.47 MPa), with a 1580 °F (860 °C) bed temperature. PICFB testing commenced December 1996. The unit achieved 250 continuous hours of operation as planned on March 8, 1997.[19,21]

EBARA PICFB pilot plant pressure vessel in place at facility
Source: EBARA [19]
9616EJ-ebar

Foster Wheeler's 10 MWth Karhula, Finland facility is duration testing a single cluster Siemens Westinghouse Power Corporation hot gas candle filter with 112 ceramic candle elements in three plenums. The filters are being tested in Foster Wheeler's circulating PFBC pilot plant.[24]

Foster Wheeler Karhula, Finland Test Facility
photo courtesy of Foster Wheeler

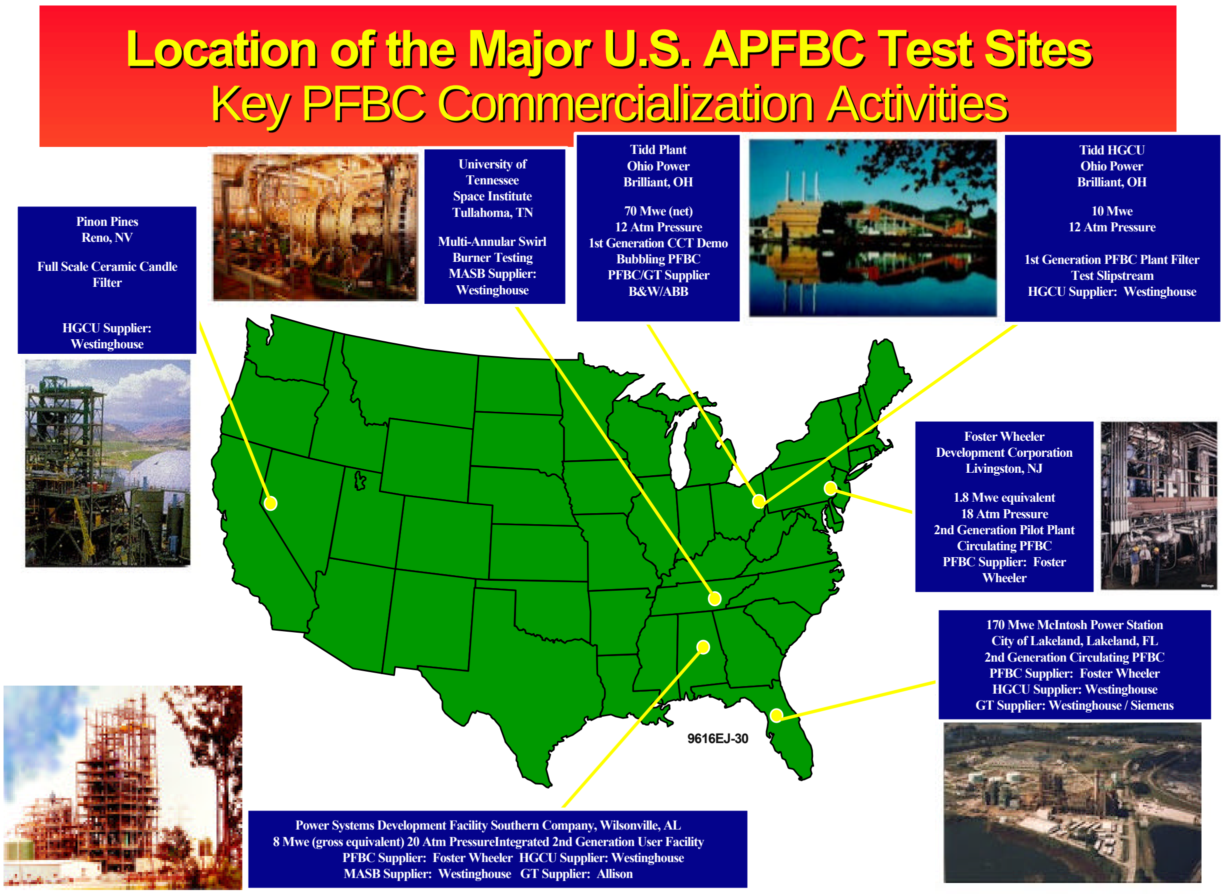
The 7 MWe (equivalent capacity) DOE/ industry-sponsored Wilsonville, Alabama Power Systems Development Facility is testing high-temperature particulate filters, and now beginning integrated APFBC operation. The carbonizer operates at about 175 psia and 1600 °F, and the PFBC operates at about the same conditions. The Siemens Westinghouse multi-annular swirl burners produce gas turbine combustion temperatures of from 2100 °F to 2350 °F, but this is air-quenched to about 1975 °F at Wilsonville to meet the Allison Model 501-KM combustion turbine limits.[22]

Power Systems Development Facility APFBC demonstration facility, Wilsonville, AL
Source: U.S. DOE [23]
9616EJ-wlsn

Department of Energy Clean Coal Technology Program

The DOE CCT program consists of several PFBC projects demonstrating the commercial viability of PFBC and supporting technology; see Figure 3-10. The Tidd plant completed its successful demonstration of the first-generation PFBC test program in March 1995. The DMEC-1 and Four Rivers have been consolidated into one project, the City of Lakeland demonstration.

Figure 3-10
U.S. Department of Energy PFBC Demonstration Projects



The 180 MWe Clean Coal Technology APFBC commercial demonstration at McIntosh Power Station in Lakeland, Florida is owned by the Lakeland Department of Electric & Water Utilities. Upon operation this will be the first commercial size demonstration of APFBC technology, and is a cooperative effort between DOE, the City of Lakeland, and Foster Wheeler Energy Corporation. Foster Wheeler is providing the PFBC technology. The plant uses a 2400 psig / 1000 ºF/ 1000 ºF steam cycle. The carbonizer operates at 1700 ºF, and the PFBC operates at 1550 ºF to 1650 ºF. The

project is scheduled to be in commercial operations by year 2001.[25] The APFBC portions of the system will be brought into operation in year 2002.

The first phase of the new project will be the testing of the Foster Wheeler (formerly Pyropower) first-generation circulating PFBC. This will be followed by the installation of a carbonizer with its cyclone and filter, and gas turbine topping combustor to convert the facility to an advanced PFBC. The completion of this project is necessary to provide the data and experience for subsequent commercial advanced PFBC plants.

APFBC Train at the Wilsonville Power Systems Development Facility (PSDF)

In parallel with the CCT program, the DOE is conducting tests of a fully integrated advanced PFBC system, at the 15 MWth proof-of-concept level (see Figure 3-11), located at the PSDF in Wilsonville, Alabama. This PFBC testing, sponsored by DOE, Southern Company Services, and EPRI, will evaluate the integration of all of the components in the PFBC system, with emphasis on the integration of hot gas cleanup ceramic filters and gas turbines.[26] This test facility, at a scale of 3 tons/hour or 6 MWe, will provide design input for the planned CCT demonstration unit.

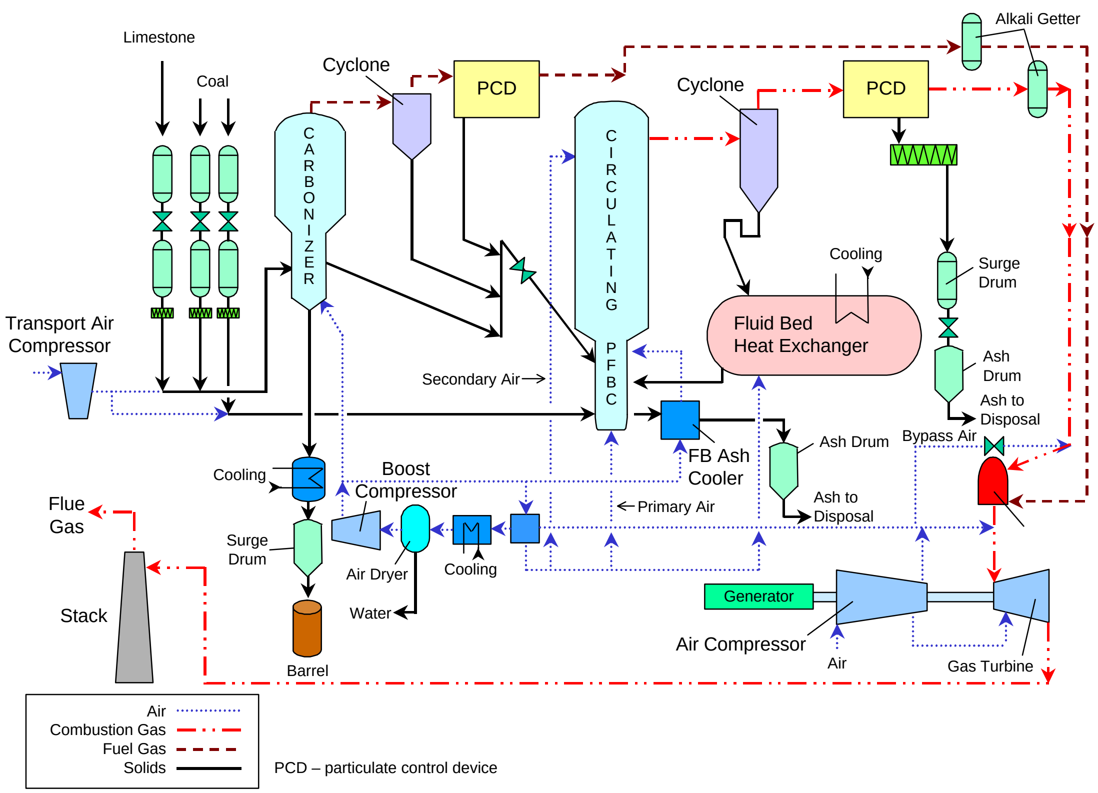


Figure 3-11
Power Systems Development Facility -- PFBC

The facility initially contains several demonstration modules:

- A transport reactor gasifier and combustor,
- An APFBC system,
- A particulate control module, and
- An advanced burner-gas turbine module.

The modules will initially be configured into two separate test trains:

- The transport reactor train (one ton/hour of coal feed), and
- The APFBC train (3 tons/hour of coal feed).

The goals of these tests are to demonstrate integration of the particulate control devices into advanced power generation systems, assess the long-term durability of the particulate control devices, demonstrate durable candle materials, and evaluate load cycling effects on the particulate control devices. Critical issues to be addressed at the PSDF include:

- The integration of particulate control devices into coal utilization systems.
- On-line cleaning techniques.
- Chemical and thermal degradation of components, fatigue or structural failures, blinding, collection efficiency as a function of particle size, and scale-up to commercial-size systems.
- Long-term endurance tests will involve about 1,000 hours of continuous particulate control device operation at nominally constant operating conditions.

3.1.2.3 PFBC Fuel Flexibility

The firing of opportunity fuel with or without co-firing of coal in utility scale power plants has emerged as an effective approach to produce energy and manage waste materials. Leading this approach is the fluidized-bed combustor. It has demonstrated its commercial acceptance in the utility market as a reliable source of power by burning a variety of waste and alternative fuel feedstocks including:

- Refuse-derived fuel
- Sewage sludge
- Pulp and paper sludges
- Biomass
- Shredded tires
- Petcoke

- Oil shale
- Low-rank coals and tailings

The fluidized-bed, with its stability of combustion, reduces the amount of thermochemical transients and provides for easier process control. The application of pressurized fluidized-bed combustor technology, although relatively new, can provide significant enhancements to the efficient production of electricity while maintaining the benefits of AFBC.

In support of FBC burning opportunity fuels there exists a considerable database of experimental testing and commercial applications that provide design and operation information. More than 170 atmospheric fluidized-bed boilers are burning alternative fuel feedstocks. An excellent source of information is the American Society of Mechanical Engineers and the DOE-sponsored International Conference on Fluidized-Bed Combustion.

Commercial applications of pressurized fluidized-bed technology use various types of coal-based fuels, including low-valued feedstocks such as lignite or “brown” coals. Both the 70 MWe Cottbus plant in Germany and the Escatron Station in Spain (see Table 3-4) use the advantages of fluidized-bed combustion to economically combust low-ranked coal.

3.1.2.4 Repowering with PFBC

Repowering with APFBC is particularly attractive, because unlike repowering with natural-gas-fired gas turbines, steam to the existing steam turbine is from the APFBC system. Instead, in APFBC, the fluid-bed heat exchanger can easily meet superheat and reheat steam temperature demands, and offers considerable flexibility for one gas turbine to provide full-rated steam for a large range of sizes of existing steam turbines. Table 3-7 provides a summary operational and performance parameters for a conceptual repowering.

Benefits of APFBC compared to other repowering technologies include:

- Low NOx emissions due to relatively low combustion temperatures, which limits the conversions of fuel nitrogen to NOx.
- Ability to easily match existing steam turbine superheat and reheat conditions.
- Use of coal or opportunity fuels.
- High energy efficiency, exceeds environmental performance NSPS requirements.
- Supports different existing plant sizes for repowering with one size APFBC and gas turbine.
- Low installed cost and O&M cost.

Table 3-7
Repowering Operational and Performance Comparison

	Existing Unit	Repowered with APFBC
Gross Output, kWe		
Gas turbine gross	--	138,400 kWe
Unit 2 steam turbine gross	112,500 kWe	105,111 kWe
Auxiliary losses	-6,500 kWe	-17,020 kWe
Net plant output, kWe	106,000 kWe	226,491 kWe
Net Plant HHV Efficiency	32.0%	42.4%
Net Plant LHV Efficiency	33.3%	44.1%
Net Plant HHV Heat Rate	10,660 Btu/kWh	8,041 Btu/kWh

Tests programs are in place for all major components, and the Wilsonville PSDF and DOE's planned APFBC CCT projects are proving large-scale integrated commercial operation. APFBC repowering can dramatically increase energy efficiency, clean the environment, and reduce production costs. A unit in start-stop duty at 20 percent capacity factor becomes a baseload coal unit with APFBC repowering, moving to greater than 80 percent capacity factor.

Concept assessment studies on APFBC repowering at several generating company sites show exceptionally low operating costs for units repowered with APFBC technology:

- Carolina Power & Light Company's L. V. Sutton plant,
- Duke Power's Dan River plant, and
- AES Greenidge plant.

This is due to the high energy efficiency of the units after repowering. Generating company production costing evaluations show, consistently, that units repowered with APFBC would become the most economical coal-fired units in their plant dispatch order — they become the premier coal-fired baseload units, the most profitable to operate full time.

3.2 RISK ASSESSMENT

Increased competition within the electric power market is driving the decision process toward enhanced performance, lower capital investment, and lower operation and maintenance expense. With this approach the power generation community is facing the need to fully understand the risks involved and potential for financial consequences. Therefore, it is imperative that the decision process evaluating the application of advanced technologies includes the identification and determination of economic risk to the investor. However, this task is not easily accomplished, primarily due to the matrix of risk elements involved including technology, economics, competition, regulatory, environmental, and project participants.

Various studies evaluated uncertainties in the application of advanced power systems, specifically coal gasification combined-cycle systems and pressurized fluidized-bed combustion. These analyses rely on a systematic approach to evaluate uncertainty in design and performance based on limited commercial experience and expert analysis. The details of a procedure using probabilistic analyses are summarized by Frey and Rubin.(27,28) By use of Monte Carlo or similar simulation techniques, simultaneous uncertainties in any number of parameters can be propagated through a model to determine their combined effect on model outputs. The model input parameters are based on information available in published studies, statistical data analysis, and the judgments of relevant experts. Compared to deterministic analysis, this approach characterizes the range of values assigned to performance and cost parameters.

An alternative approach applies process contingencies to capital cost estimates by utilizing a scale that assigns a percentage contingency to the cost based on the development status, which can range from laboratory studies to full commercialization, in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment. A typical example of this methodology(8) is the EPRI TAG™, which assigns process contingency as shown in Table 3-8.

This approach attempts to match financial exposure with the value of specific equipment or process. However, in today's competitive environment this broad approach may overly penalize the technology with additional cost. This process does not provide the decision-maker with specific information about the effects of risk on system performance. Additionally, the decision-maker is not afforded the opportunity to adjust the basis of the applied risk value against recent technology advances or his/her knowledge and process or product insight.

Table 3-8
Technology Status Versus Process Contingency

State of Technology Development	Process Contingency as a Percentage of Installed Cost
New concept, limited data	40+
Concept with bench scale data	30 to 70
Small pilot plant data	20 to 35
Operational full-size module	5 to 20
Commercial process	0 to 10

Other techniques represent risk through relative rankings of alternative technologies. The major focus in these risk analyses is projecting future performance and cost based on existing knowledge of pre-commercial units and conventional technologies. Judgment by the decision-maker is then required to apply these data against the investment decision.

Specific to the technologies presented in this report, the purpose of conducting a risk assessment associated with each of the advanced plant configurations is to identify an expected cost of advancing the technology from its present status to full commercialization by 2005. Two methods are used to assist the decision-maker in defining the effect of risk on the process operation and economics. The first, described in this section, evaluates technology risk through a delineation of known problem areas. Issues are briefly discussed and qualified in terms of potential performance shortfall and alternatives or corrective actions presently available to the decision-maker. The second method, described in Section 4.3, uses sensitivity of various operating parameters, including capacity factor, heat rate, production cost, and capital cost, to evaluate the effect of risk elements on the process economics.

To assist in the analysis of clean coal technologies, an approach is presented to evaluate the elements of technology risk for application of advanced coal-based technologies. The development of systems and components relative to commercial status, and the status of mitigation efforts being pursued by developers and/or DOE aimed at ensuring that technology reaches commercialization for market penetration by 2005 are provided. This approach to risk evaluation permits the decision-maker the ability to adjust performance and cost parameters given the information available.

3.2.1 Integrated Gasification Combined Cycle

The DOE has embarked on a program to develop IGCC as a product that results from the interaction of several ongoing R&D programs. These include hot gas desulfurization, hot gas particulate removal, and advanced turbine systems. DOE R&D activities are focused on developing second-generation IGCC components, concepts, and subsystems to proof-of-concept scale, or as a major slipstream on a planned IGCC demonstration project. Primary R&D areas are hot gas desulfurization, hot gas particulate removal subsystems, and other gas cleaning/ conditioning technologies. At present there are three IGCC demonstration projects under the CCT program at a total cost of approximately $1.0 billion. These demonstration projects plan to incorporate many hot gas cleanup advancements. Parallel initiatives are underway to develop advanced turbine cycles that will be incorporated into future IGCC systems.

Commercialization of hot gas cleanup will result in lower capital cost, since hot gas cleanup systems are less complex than cold desulfurization. Also, hot gas cleanup will improve efficiency approximately two percentage points over cold gas cleanup. Development of advanced gasifiers and gas turbines will provide even greater improvements in efficiency and cost that are vital for widespread commercialization of the technology. The DOE program goals as set forth in the Clean Coal RD&D Program Plan[3] are shown in Table 3-9.

Table 3-9
IGCC RD&D Program Goals

	2000	**2008**
Gasification Power System	**Second Generation IGCC**	**Integrated Gasification Advanced Cycle**
Net electric system efficiency (HHV)	42	$\geq$50
Sulfur dioxide emissions relative to NSPS (1.2 lb/10^6 Btu & 90% reduction of potential)	1/10	1/10
NOx emissions relative to NSPS (0.6 lb/10^6 Btu)	1/10	1/10
Air toxic emissions relative to 1990 CAAA law	To meet	To meet
Capital Cost (1999 $'s) $/kW*	$1,250	$1,000
COE relative to conventional PC power plant	0.8	0.75

* Capital Costs are expressed as overnight construction costs; 1995 $'s were escalated based on Chemical Engineering Index.

Achieving these goals will require development and demonstration of process elements considered to be at risk of reaching performance and/or cost objectives defined for market acceptance. IGCC plant process areas identified as having associated risk or uncertainty are listed in Table 3-10. For each element of risk, a narrative of potential areas of risk is provided, along with a review of present efforts to reduce or eliminate risk. To build a level of confidence as to the probability of commercial availability by 2005, a level of process contingency should be assigned by decision-makers in the framework of any discrete economic analysis. Components not listed are either considered to be commercially available or have sufficient operational history to define capital and operating costs within acceptable levels of confidence.

Table 3-10
IGCC Assessment of Risk

System	Defined Risk Elements
Gasifiers - Air Blown - Oxygen Blown	 Hot Gas Valves Ash Quench Fuel Gas Recycle Integration
Hot Gas Desulfurization - Transport Reactor - GE Moving-Bed Desulfurizer	 Process Control Sorbent Attrition Hot Gas Valves Sorbent Capacity
Sulfur Recovery - Sulfator	 Conversion Efficiency Capital Cost
Particulate Filters	Filter Elements Filter Element Cleaning Process
Combustion Turbines	Integrated Operation

3.2.1.1 Gasifiers

The IGCC power generation concepts presented in this evaluation guide use two gasifier designs from the DOE CCT demonstration program: an air-blown gasifier and an oxygen-blown gasifier.

- **Air-Blown Gasifier**

  DOE's CCT demonstration program with air-blown gasification is based on the KRW Gasification Process. This process was originally developed by Westinghouse Synthetic Fuels

Division with government support. Development of the gasifier proceeded through the 24 ton/day pilot plant at Waltz Mill, Pennsylvania and has operated on both air and oxygen. In the early 1980s, the gasifier technology was transferred to a joint entity of M.W. Kellogg, Rust Engineering, and Westinghouse, called KRW Energy Systems, Inc. Significant to the development of the KRW process was the co-feeding of limestone sorbent with coal to achieve a high level of in-bed sulfur capture. In 1987 and 1988 DOE supported a test program that integrated the KRW in-situ desulfurization with a fixed-bed zinc ferrite polisher. Also tested were hot ceramic candle particulate filters and high-efficiency cyclones.

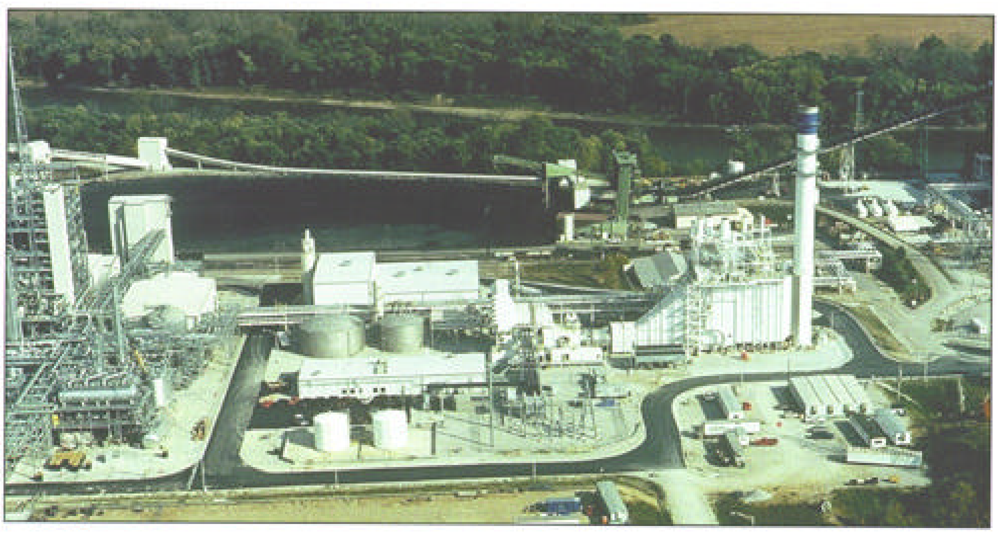
Currently, Sierra Pacific Power Company is participating in an IGCC demonstration power plant that uses a KRW air-blown gasifier with in-situ desulfurization to gasify 88 tons/day of western coal and produce 99 MW of electric power. Known as the Piñon Pine Power Project, this project was selected by the DOE for funding under CCT Round IV. M.W. Kellogg is supplying the engineering of the gasifier island, which includes the gasifier and hot gas polisher. The objectives of the Piñon Pine project include meeting the power needs of Sierra Pacific customers and demonstrating the technical, economic, and environmental viability of the KRW IGCC power plant on a commercial scale. The project is also aimed at demonstrating the effectiveness of hot gas cleanup and the operation of a low-Btu fuel gas combustion turbine. The project was completed in late 1996 and began commercial operation on gas in 1997. The project is currently proceeding with total integration with syngas.

M.W. Kellogg's marketing of the KRW gasifier will be based on operational data from a successful demonstration. They have developed capital cost estimates for the gasifiers based on the cost to complete construction at Piñon Pine. The costs of gasifiers for larger plants are not expected to decrease significantly due to economies of scale, due to the optimum system modules presently defined in the 100 MW range.

Elements of risk that may presently be considered in application of the KRW technology include the integration of the gasifier at high throughputs and the continuous operation in an ash agglomerating mode. The integration aspects will be established through the CCT program demonstration at Piñon Pine. However, specific components requiring full-scale demonstration include the hot gas valves and the ash quench portion of the gasifier. Although this unit has been demonstrated at the 24 ton/day level, the CCT demonstration requires a several-fold scale-up.

C **Oxygen-Blown Gasifier**

DOE's Wabash River CCT oxygen-blown gasification program uses Dynegy's Destec gasifier. A 1,600 ton/day gasifier demonstrated this design at the Dow Plaquemine, Louisiana chemical complex, with full operation since 1987. The Destec gasifier at Plaquemine operated on subbituminous coal, and achieved 65 percent availability. The primary difference between the original Destec gasifier design and the Wabash River gasifier is that the Wabash River project, shown in the photo below, operates on high-sulfur bituminous coal rather than subbituminous and is projected to have a high availability. The plant is demonstrating long-term operation on high-sulfur bituminous coal, and the transition to a utility application has gone smoothly. The bituminous coal is not as reactive as the subbituminous, and requires some recycle of fuel gas to the second stage of the gasifier. The Wabash gasifier has a throughput of 2,400 tons/day.



View of DOE's Wabash River Clean Coal Technology demonstration.

A major element of risk when assessing the application of this gasifier is the system integration of the gasifier with fuel gas and particulate recycle. This risk should be mitigated upon completion of the CCT demonstration; after that, the technology should be classified as commercial. The Destec gasifier was fired with coal in August 1995, and the gas turbine was fired with fuel gas in October 1995. In 1996, the gasifier accumulated over 2,000 hours of operation on coal and the combined cycle operated over 1,500 hours on syngas. During 1997, the gasifier accumulated over 3,000 hours of operation on coal. In March 1998 the Wabash gasifier produced 1 billion Btu of fuel gas, a milestone that had not been reached by any other gasifier in the world.

3.2.1.2 Hot Gas Desulfurization

DOE identifies hot gas desulfurization (HGD) as the means by which the sensible heat of the gasification product gas may be retained. This increases IGCC efficiency, maximizes power from the gas turbine, and improves economics. The DOE is sponsoring research in advanced methods for controlling contaminants for hot gas streams of IGCC systems. The programs focus on hot gas cleanup technologies that match or nearly match the temperatures and pressures of the gasifier, cleanup system, and power generator. The purpose of the development effort is to eliminate the need for expensive heat recovery equipment and to avoid the efficiency losses associated with fuel gas quenching. Hot gas cleanup should offer significant advantages over cold gas cleanup for IGCC applications. The principal advantage is that the sensible heat retained in the fuel gas allows the gas turbine inlet temperature to be reached with less fuel. The conserved heat is applied to enhancing the higher efficiency chemical energy conversion in the gas turbine rather than the less efficient generation of steam. In contrast, in cold gas cleanup gas cooling, additional steam must be raised, resulting in high steam power relative to chemical power for the IGCC plant. Hot gas cleanup is best applied for air-blown gasification because it retains the sensible heat of the large gas volume containing about 50 percent nitrogen.

The major development issue associated with HGD is the need to demonstrate operation for an extended period at a scale equivalent to commercial application. Until this is accomplished, IGCC plants will use proven cold gas cleanup. A commitment to use an HGD system has significant financial risk consequences. Once an IGCC plant is designed with hot gas cleanup, the entire heat and material balance of the plant is dependent upon successful operation of the cleanup system. Conversion back to cold gas cleanup is not a practical option to avoid performance risk. A converted plant would not operate correctly.

The key development component in a regenerable HGD process is the sorbent. The mixed oxide sorbent is subjected to the most severe of conditions in which it is sulfided at 1100 ^{o}F, physically transported, and regenerated back to the oxide at up to 1400 ^{o}F. In doing so, the sorbent must retain its capacity and physical integrity; both criteria are key issues in sorbent development. HGD sorbents have potential for additional market penetration besides IGCC. The removal of H_2S from tail gas streams in a variety of petrochemical plant operations provides an open opportunity for HGD processes.

Sulfur capacity is more of an issue with sorbents utilized in the GE moving-bed process than in fluid beds, since the rate of sorbent circulation is inversely proportional to the amount of sulfur captured per unit of sorbent. Excess circulation can lead to sorbent attrition and an imbalance in the heat recovery from the regeneration process. Sorbent sulfur capacity is less of an issue with the fluid bed and transport reactors due to the low utilization of sulfur capacity in those processes. Attrition resistance is key in the fluidized processes because of the continuous activity in the beds.

A third issue in the development of HGD sorbents is avoiding the formation of sulfates during regeneration. The principal cause of sulfate formation is the presence of excess oxygen at 1000 ^{o}F regeneration temperatures. Sulfate can be removed by heating the sorbent to 1400 to 1500 ^{o}F, but this approaches the sorbent sintering temperature.

Research objectives are aimed at developing sorbents to resolve these issues. During these efforts sorbent formulations will be a compromise to meet the operational criteria for an IGCC installation. Phillips Z-Sorb™, a commercially offered zinc-based sorbent with a nickel promoter, has been tested and found to be attrition resistant and to suppress the formation of sulfates. This sorbent was the initial fill selected for both Tampa Electric and Piñon Pine CCT projects.

Long-term stability of sorbents has yet to be demonstrated. Up to 200 hours of testing at the GE process development unit is a precursor to its demonstration in a slipstream from the Tampa Electric IGCC project. Long-term stability of sorbents will also be demonstrated at the Piñon Pine project, which has a transport reactor HGD.

DOE's Hot Gas Desulfurization Program(29) is based on achieving certain sorbent requirements:

- Regeneracy (the primary goal).
- Withstand highly reductive gas atmospheres.
- Operate at absorption temperatures of 1000 to 1500 ^{o}F.
- Operate at pressures of 300 to 600 psi.
- Demonstrate separate small volume percentage of H_2S from fuel gas (less than 0.5 percent).
- Operate at regeneration temperatures of 1075 to 1450 ^{o}F.
- Recover reactivity and resist attrition.
- Provide long life at low costs.

Research into high-temperature and high-pressure control of sulfur species includes primarily those sorbents made of mixed-metal oxides, which offer the advantages of regenerability. These are predominantly composed of zinc, formed into a media structure that can be utilized in reactors of either fixed-bed, moving-bed, fluidized-bed, or transport configurations.

The DOE desulfurization test program is composed of three major components: bench-scale research, pilot-plant operation, and demonstration as part of the CCT projects. Of foremost concern is the mechanical integrity of the sorbent, which is dependent on the reactor configuration and process chemistry. Participating in bench-scale research are the General Electric Corporation (GE) Research and Development Center, Research Triangle Institute (RTI), and DOE.

Providing pilot-plant facilities is the DOE's Federal Energy Technology Center (FETC) in Morgantown, West Virginia. The FETC hot gas desulfurizer PDU has dual capability in examining both fluidized and transport reactor modes of operation.

Companies that are assisting in optimizing manufacturing techniques are: United Catalysts of Louisville, Kentucky; Contract Materials Processing of Baltimore, Maryland; Calcicat Corporation, Erie, Pennsylvania; and Phillips Petroleum of Bartlesville, Oklahoma. Other catalyst manufacturers have shown interest and possess additional capabilities.

- **Transport Reactor Hot Gas Desulfurization Unit**

  The transport reactor hot gas desulfurization unit is based on years of petrochemical operation as a fluid catalytic cracking process, and is planned as the reactor for the hot gas desulfurization unit in the Piñon Pine CCT project. The transport reactor was selected over the fixed-bed reactor for HGD at Piñon Pine because of inherent issues that had developed with the fixed bed during testing at FETC. These included:

  – Requirement for high-temperature valves with positive shutoff.
  – Difficulty in controlling regeneration temperature.
  – Off-gas with varying SO_2 concentration.

  One of several zinc-based sorbents considered as a potential candidate, Z-Sorb™ III, is under development by Phillips Petroleum Company. Bench-scale tests conducted by M.W. Kellogg and Research Triangle Institute have indicated that Z-Sorb™ III can be used as a desulfurization sorbent in fixed bed, fluidized bed, and the transport reactor. M.W. Kellogg conducted sorbent tests at the Transport Reactor Test Unit (TRTU) in Houston, and gained sufficient confidence in the transport technology to utilize it at Piñon Pine. At Piñon Pine, M.W. Kellogg selected Z-Sorb™ III as the design sorbent because it has demonstrated the best mechanical strength of the sorbents tested for this application. Also, the nickel content in Z-Sorb™ suppresses sulfate formation at the onset of regeneration at lower temperatures. Z-

Sorb^{TM} has not been shown to be tolerant of steam under regeneration conditions, so M.W. Kellogg elected to use dry air, while reducing the level of sorbent utilization to about 5 to 6 percent of theoretical, to manage the bed temperature. While the Z-Sorb^{TM} utilization is minimized, sorbent circulation is increased with a somewhat compromised requirement for higher sorbent inventory. The process needs demonstration at a full-scale project, and commercialization depends on successful operation at Piñon Pine.

The transport reactor desulfurizer consists of a riser tube, a disengager, and a standpipe for both the absorber section and regeneration section. The desulfurizer system train is capable of processing gas equivalent to that needed for about 100 to 150 MW IGCC plant. For the Piñon Pine CCT project, the absorber contains an inventory of 15 tons Z-Sorb^{TM} sorbent, which is circulated at a rate of 225,000 lb/h. The absorber riser is 42 inches diameter by 50 feet high.

The regenerator is a 3-inch-diameter and 70-foot-high transport reactor through which 36,000 lb/h of sorbent from the absorber passes through the regenerator riser, disengages, and transfers back to the absorber through the standpipe. Regeneration is conducted with neat air to minimize heat release and limit temperatures to 1300 ^{o}F. Regeneration heat has a negligible effect on sorbent temperature in the absorber. Regeneration off-gas containing predominantly SO_2 is sent to a sulfator to be absorbed by the excess limestone in the LASH and converted to $CaSO_4$.

Elutriated particles are disengaged from gas passing through the high-efficiency cyclones at the top of the absorber, and some Z-Sorb^{TM} is also retained by the regeneration outlet gas. The total fines elutriated from the transport desulfurization absorber are predominantly 20 micron particles from the gasifier, and the balance being Z-Sorb^{TM}. These are recovered downstream in the ceramic candle gas filter and are added to the LASH in the sulfator. Current design practice is to send the fines to a separate combustor, thereby permitting a sulfator design that needs to handle only the larger solids from the gasifier. Loss of sorbent is estimated to be 100 lb/h per train for 100 to 150 MW equivalent gas flow (air-blown gasifier).

The salient features of the transport reactor desulfurizer are:

- Based on proven commercial technology.
- High mass throughput per capital cost.
- Efficient conservation of fine particles.
- Effective temperature control.

– Small physical footprint.

C **Moving-Bed Hot Gas Desulfurizer**

General Electric Corporation (GE), with support from DOE, is developing an advanced hot gas cleanup process to provide test data from the use of zinc ferrite, zinc titanate, and Z-Sorb™ sorbents. The process consists of a moving-bed absorber, a moving-bed regenerator to regenerate the sorbent and to produce a high SO_2 concentration tail gas, a regeneration gas recycle, and a solids transport system. Process development unit (PDU) tests of this process integrated with GE's air-blown, fixed-bed gasifier began in June 1990.

Compared to the fixed-bed concept, the moving-bed system has, potentially, several advantages, including dedicated operation in separate vessels, continuous replacement of used sorbent, positive temperature control, and constant SO_2 concentration in the regeneration gas. These advantages are a result of the following design features. Two vessels are used, each designed and dedicated to one function. The absorber vessel is a countercurrent flow reactor with continuous flow of coal-gas and intermittent flow of sorbent. Fresh sorbent may be added to the top of the absorber, and sulfided sorbent, containing captured gasifier particulates, can be removed from the bottom. The regenerator vessel is a multistage, co-current reactor, which allows for control of the exothermic regeneration reaction and prevents overheating, sintering, and destruction of the sorbent. The regenerator gas streams flow continuously, while the sorbent moves intermittently as in the absorber. The moving-bed process also uses recirculation of the regeneration gas for temperature control, and, unlike the fixed-bed concept, offers the advantage of diluent flow continuously through a single vessel.

The moving-bed concept, while offering certain process advantages, does not provide mechanical design advantages compared to the fixed-bed concept. High-temperature and high-pressure valves and piping are required in both cases, while the moving bed also includes hot sorbent transport equipment. Also, it was found during testing that the presence of chlorides in the fuel gas created operational problems in the regeneration loop in the form of chloride deposits on heat exchange surfaces. As a result, GE incorporated a fluidized-bed chloride removal bed ahead of the moving-bed absorber. The following accomplishments have been achieved from the GE Moving-Bed Project:

– Six-inch hot fuel valve was tested and found to be fully functional.
– Configuration problems in absorber and regenerator were solved.

- – Automatic control of sorbent movement was fully demonstrated.
- – Over 90 percent chloride removal was fully demonstrated.
- – Satisfactory sulfur dioxide levels obtained in slipstream to acid plant were fully demonstrated.
- – System is mechanically ready for commercial demonstration at the Tampa Electric IGCC plant.

The moving-bed concept requires a sorbent material with sufficient mechanical strength properties to allow movement through the system without excessive materials breakup or attrition that would adversely impact system economics by introducing a high sorbent makeup cost. For system studies, GE has estimated a makeup rate of 0.5 percent or less per cycle. The actual makeup rate must be determined by the operation of the PDU over multiple cycles. This makeup rate is one of the prime determinants of the process economics.

The sorbent utilization, which is the degree to which the sorbent is sulfided, was shown to decrease with increasing absorption/regeneration cycles. GE and FETC established an acceptance criterion that the sorbent maintain at least 50 percent theoretical capacity over 100 cycles for commercial application. The actual utilization also must be determined during PDU testing. A decrease in utilization will increase the circulation rate and thus may increase sorbent makeup.

The GE moving-bed PDU absorbs sulfur at the gasifier pressure but regenerates at a relatively low pressure, primarily for testing convenience. If higher pressures are needed for off-gas processing, the regenerator can be designed for higher pressures.

The moving-bed system, with its two vessels and associated lock hoppers and valving stacked vertically, has an overall system height for the GE PDU of 85 feet. Scale-up will increase the diameter of the vessels more than it will the height of the system. However, the capacity of a single train will be limited by practical size constraints. GE is projecting a single moving-bed absorber/regeneration set for a gasifier train of approximately 100 MWe in capacity for air-blown gasifiers and 250 MWe for oxygen-blown applications.

The moving-bed concept should be applicable to any metal oxide or mixed metal oxide sorbent. Iron oxide can be used at lower temperatures and where only moderate sulfur removal is required. For high sulfur removal at intermediate temperatures in a moderately reducing gas stream (such as in air-blown fixed-bed gasifiers), zinc ferrite is the sorbent of choice. For higher temperatures and more reducing conditions, advanced sorbents such as zinc titanate may be applicable, and are currently the subject of testing.

Following are the salient features of the moving-bed process:

- Permits good gas/solid contact.
- Process as complicated as the fixed bed.
- Requires high temperature valving.
- Requires attrition-resistant sorbent for economical operation.
- Heat removal and temperature control require recycle loops.
- Maintains steady, predictable level of SO_2 in regeneration off gas (12 percent for zinc ferrite; 15 percent for zinc titanate).

Together, the process elements, including the high-temperature, high-pressure valves and piping, sorbent material, and process control, can comprise 25 to 30 percent of the desulfurizer system capital cost. Current plans for demonstration include processing a 10 percent slipstream from the Tampa Electric IGCC CCT project, and possible transport of regeneration gas to a sulfuric acid plant. GE is currently considering several sorbents for the initial fill at Tampa. These include Z-Sorb™ III, which was tested at the Schenectady, New York PDU and was reported to suffer from loss of capacity due to the presence of steam. It is being considered for the first fill at Tampa since the lower sulfur loading from the slipstream demonstration and the lack of hydrocarbons condensed from the Texaco fuel gas should not produce steam during regeneration.

The GE moving bed is the process used for significant testing of the hot gas desulfurization sorbents developed under the support of DOE/FETC. This system was developed as a successor to the fixed-bed concept, and offered several advantages over the fixed bed. However, the current activity at DOE in the areas of hot gas desulfurization leans toward the transport reactor rather than the moving bed, for several significant reasons:

- The transport reactor can operate without a pre-filter to remove carbon-containing particulates. These are carried through with elutriated sorbent and captured on the barrier filter.

- Sorbent particles are circulated to extinction and elutriated out with the gas. There are no size requirements.

– Regeneration temperature is controlled by limiting air flow to the regenerator loop. Nickel additives are preventing sulfate formation.

– Sorbent utilization is very low, and can have a broad range of sulfur capacity and still be utilized.

3.2.1.3 Sulfur Recovery

Two concepts of sulfur recovery support the gasifier configurations used in this guide. The Destec design uses a commercial sulfuric acid plant. The KRW gasifier, with in-situ desulfurization, is dependent upon the successful integration with a sulfator.

C **Sulfator**

The sulfator is a fluidized-bed combustor operating at atmospheric pressure, which collects and burns various solids and gas streams from the gasification process. The bed drain material produced from the gasifier consists of a mixture of ash agglomerates, spent limestone sorbent, and partially used sorbent (LASH, limestone and ash). The CaS formed in the sorbent can potentially produce H_2S in a landfill if exposed to an acidic solution. The purpose of the sulfator is to convert CaS to $CaSO_4$ by roasting in air at a temperature high enough for rapid conversion without excessive emissions of SO_2. Prior studies[30], particularly the Southern Company Wansley Station study, base their relatively low cost estimates for the sulfator on availability of a KRW gasifier with a continuous sulfation reactor. Recent laboratory testing[31] has been conducted by M.W. Kellogg. KRW LASH was tested in the Transport Reactor Test Unit (TRTU) to determine the level of oxidation that could be achieved. When operating the sulfator at 1600 ^{o}F, oxidation levels in the range of 50 percent were achieved, with some results as high as 74 percent depending on oxygen concentration and particle size.

An alternative to a sulfator, in the event that 90 percent conversion cannot be reached, is to add LASH to a coal-fired AFBC boiler and adjust pricing accordingly. Current design practice is to send the fines to a separate combustor, thereby permitting a sulfator design that needs to handle only the larger solids from the gasifier. At this point, availability of a commercial sulfator reactor is dependent on the success achieved during the CCT program at Piñon Pine. Piñon Pine utilizes circulating bed heavy oil cracking technology for the sulfator. The sulfator depends upon the presence of carbon in the LASH to maintain reaction temperature. The result is a high-ash, low heating value feed for the sulfator, resulting in inherently marginal economics.

3.2.1.4 Particulate Filters

Particulate filter devices for IGCC applications are unproven at temperatures above 650 ^oF. The Demkolec/Shell Coal Gasification Plant at Buggenum, The Netherlands uses a ceramic particulate filter at 650 ^oF to remove particulates prior to water quenching the raw fuel gas. This eliminates residual particulates in the wastewater stream. Ceramic candle filters are under development for PFBC applications, the most notable being the Tidd CCT demonstration at temperatures suitable for IGCC operation, 1100 ^oF. Problems are encountered due to the reducing gas vs. oxidizing gas in a combustion process, the irregular nature of the solids, and in the filter cleaning process. These problems have resulted in reducing both filter durability and performance, requiring larger surface areas, lower filter velocities, and shorter filter lifetimes.

DOE is supporting development of particulate filters for IGCC and PFBC applications. DOE has a Particulate Cleanup Program, which conducts technology demonstration projects and applied research to address the adverse filtration conditions and filter system issues. There are significant milestones in the particulate cleanup program, including:

1985-1992	Grimethorp PFBC, clay bonded SiC candle filters
1986-1989	NYU PFBC Test Facility, ESP, granular bed, and cross flow filters
1987-1988	KRW fluidized bed, clay bonded SiC candle filters
1992	Texaco Gasifier at Montebello, 11 separate filter tests
1996-present	Wilsonville Power Systems Development Facility

The objectives of the Wilsonville Power Systems Development Facility (PSDF) include developing advanced coal-fired power generation technologies through the testing and evaluation of hot gas cleanup systems. In addition, this program will evaluate other major components at the pilot scale and demonstrate the performance of the components in an integrated mode of operation and at sizes that will require scaling up to commercial systems. The major particulate control device issues to be addressed include the integration of the particulate control devices into coal utilization systems, on-line cleaning techniques, chemical and thermal degradation of components, fatigue or structural failures, blinding, collection efficiency as a function of particle size, and scale-up of particulate control systems to commercial size.

The high-temperature gas cleanup (HTGC) systems are designed to achieve sufficient levels of particle and alkali removal to protect the gas turbine from erosion, deposition, and corrosion damage. To do this the HTGC must meet certain performance levels:

- Achieve particle-removal efficiency to meet environmental and turbine protection standards.
- Meet performance standards -- outlet particulate loadings less than 20 ppm by weight with no more than 1 weight percent particles exceeding 10 microns and no more than 10 weight percent exceeding 5 microns.
- Control alkali content (total sodium plus potassium vapor) to less than 50 ppb(w).
- Limit the maximum pressure drop across each HTGC train to 10 psi.
- Limit the temperature drop to less than 100 ^{o}F across the carbonizer HTGC train.

The DOE test program demonstrated the feasibility of technology for particulate removal, pressure drop, and heat loss requirements for advanced power systems. However, technical issues such as filter strength, sealing and longevity, and cleaning methods require resolution as part of the program.

The capital cost of particulate filters is divided between the vessel and the filter elements by about 50:50. The elements of risk are primarily those of the filter elements, which have the potential of falling short of stated goals for successful operation.

3.2.1.5 Combustion Turbines

The commercialization of IGCC plants requires the successful development of combustion systems for high-temperature, low-Btu fuel gas. Gas turbines in IGCC applications may be adjusted for somewhat larger mass flow rates, higher pressures, or lower combustion temperatures, to accommodate the higher flow of fuel gas. The reduced combustion temperature can result in lower thermal NOx emissions, provided that the hydrogen content of the gas is small compared to the CO content. The relatively high flame temperature of hydrogen tends to increase NOx emissions, even though its volumetric heating value is only about one-fourth that of natural gas.

- **Low Heating Value Gas**

  The volumetric heating value (Btu/scf) of gas from a typical oxygen-blown gasifier is about 30 percent of the heating value for natural gas, and the heating value for air-blown gasifier gas can be as low as 10 percent of the heating value of natural gas. As a result, between 3 and 10 times as much fuel gas (on a volumetric basis) is needed to attain the rotor inlet temperature for which gas turbines are designed. Modifications needed to accommodate medium- or low-Btu gas are described by DeCorso and others [32]:

- Medium-Btu gas (200 to 400 Btu/scf) can be burned in modified versions of either conventional or dry low-NOx (DLN) combustors. The conventional combustors might require lean-burn design and water or steam injection for NOx control, and DLN combustors would require fuel gas port re-sizing and development testing.

- Low-Btu gas (90 to 200 Btu/scf) can be burned in modified versions of conventional combustors with enlarged combustion zones to accommodate the increased volumetric flow of fuel gas.

Larger mass flow rates through the combustor and expander are normally handled by blade path adjustments to allow increased flow, or by increased pressure through the first expander stage. The inlet temperature to the first-stage nozzles of the turbine may be reduced by 50 to 75 ºF in order to maintain original design temperatures throughout the various turbine stages. This is required due to the different gas properties of the syngas combustion products relative to natural gas. This lower inlet temperature will help reset the choked flow parameter to original design values. A lower combustion temperature can improve the durability for the hot parts, but the larger flow of lower-energy gas can cause problems with flame stability such as blowout. Also, the changed combustion characteristics of lower-energy gas can increase CO emissions.

There are two basic types of gas turbine NOx emissions: thermal NOx, which is formed from nitrogen in the combustion air, and fuel-bound nitrogen (FBN) NOx, which is formed from NH_3 in the fuel gas. All of the nitrogen in the NH_3 is normally converted into NOx during combustion. Thermal NOx can be controlled by combustion-based methods, such as staged combustion or water injection, but these methods are not effective in controlling FBN NOx. If the total NOx (thermal plus FBN) leaving the gas turbine exceeds allowable limits, then a supplementary NOx reduction process, such as selective catalytic reduction, may be required.

To meet development requirements, DOE is supporting the construction and operation of a combustion system simulator to demonstrate long-term operation, characterization of fuel and its contaminants, and characterization of emissions. This simulator enables modifications of air/fuel ratio, fuel composition, and fuel temperature, resulting in design modifications to the fuel nozzle and combustion liner of existing turbine frame designs.

- **Advanced Turbine System (ATS) Program**

Another DOE program assisting IGCC and PFBC commercialization is the Advanced Turbine System (ATS) Program. DOE initiated the ATS program in 1992 with the target of developing and commercializing gas turbine combined cycles by 1998 with LHV efficiencies of at least 60 percent (HHV efficiencies of 54%). The current ATS designs are fueled by natural gas, but the program also includes links to coal-based systems such as IGCC and PFBC. Both GE and Siemens-Westinghouse have commercialized some of the ATS features into their near-term product lines, as shown in Table 3-11.

Table 3-11
"G" and "H" Gas Turbines Performance

	Siemens-Westinghouse 501G	General Electric MS7001H
Transition cooling	Steam	Air
Turbine cooling	Air	Steam
First shipment	1996	2000
Compression ratio	19.2:1	23:1
Rotor inlet temperature	2560 ^{o}F	2600 ^{o}F
Exhaust temperature	1100 ^{o}F	*
Mass flow rate	1200 lb/s	1230 lb/s
Power, simple cycle	230 MW	*
Heat rate, simple cycle, LHV	8,860 Btu/kWh	*
Efficiency, simple cycle, LHV	38.5%	*
Power, combined cycle	*	400 MW
Efficiency, combined cycle, LHV	58%	60%
Efficiency, combined cycle, HHV	52.3%	54.1%
NOx, gas, dry	25 ppm	9 ppm
NOx, oil, dry	42 ppm	

*Information not available at time of printing.

The GE MS7001G and MS7001H turbines fueled on natural gas are planned for commercial operation in 2000 at 60 percent combined cycle efficiencies(33), and the first shipment of the 58 percent efficient LHV Siemens-Westinghouse 501G has been announced.(34) The development of turbines to operate on low-Btu gas, along with the ATS Program, raises the confidence level for commercial availability of large, high-efficiency turbines by 2005.

- **Gas Turbine for this IGCC Study**

  The gas turbine generator used for this study is a modified version of the Siemens-Westinghouse 501G turbine. Two component modifications are required for commercial operation with the IGCC:

  – Replacing the original "can-annular" combustors with two external topping combustors. Customized external combustors have been substituted for "can-annular" combustors at an equivalent "pilot plant" size (about 1 MW equivalent). Development of a concept with pilot plant data to full-size applications typically adds between 20 and 35 percent to the capital cost of the combustor.

  – Increasing the nozzle area of the first turbine stage to accommodate the increased mass and volume flow of the low-Btu gasifier fuel gas. Commercial turbines have been developed to operate with low-Btu gas. However, since the selected gas turbine is an advanced concept that has not been modified in this way, the developmental status of this modification can be characterized as equivalent to pilot plant scale, which typically adds between 15 and 25 percent to the capital cost of the expander stages.

3.2.2 Pressurized Fluidized-Bed Combustion

Advanced PFBC research and development programs underway by the DOE and its industrial partners have operational and performance goals that can establish PFBC as a commercial power generation technology. The near-term and longer-term goals for PFBC are as follows:

- By 2000, develop an advanced coal-based power system capable of 42 percent efficiency HHV with emissions at 1/3 NSPS, at COE comparable with conventional power plants. Comprehensive design studies are to provide a basis for advanced power systems to meet 2010 performance goals.

- By 2005, have market-ready PFBC systems with efficiency of 45 percent HHV, emissions of 1/5 to 1/10 present regulations, and costs equivalent to conventional technology.

- By 2010, develop PFBC systems with 45 to 50 percent efficiency HHV, emissions less than 1/10 present regulations, and costs lower than conventional systems, capable of firing a variety of coals and wastes.

Scaled-up first-generation bubbling PFBC technology based on an ABB Carbon design will meet the year 2000 goal, when configured with a supercritical steam cycle (3500 psig/1050 ºF/ 1050 ºF). To achieve PFBC efficiencies that are consistent with the goal of 45 percent HHV by the year 2005 and 45 to 50 percent HHV by 2010, development of an advanced turbine system operating on a flue gas stream, combined with hot gas cleanup, with an integrated carbonizer/combustor needs to be demonstrated. Demonstrations are planned at Wilsonville in the year 1999 and in DOE's planned APFBC CCT project in the year 2002.

Achieving the DOE system goals require development and demonstration of process elements. Development elements are indicated in Figure 3-12, and their status is shown in Table 3-12.

Figure 3-12
APFBC Developmental Elements

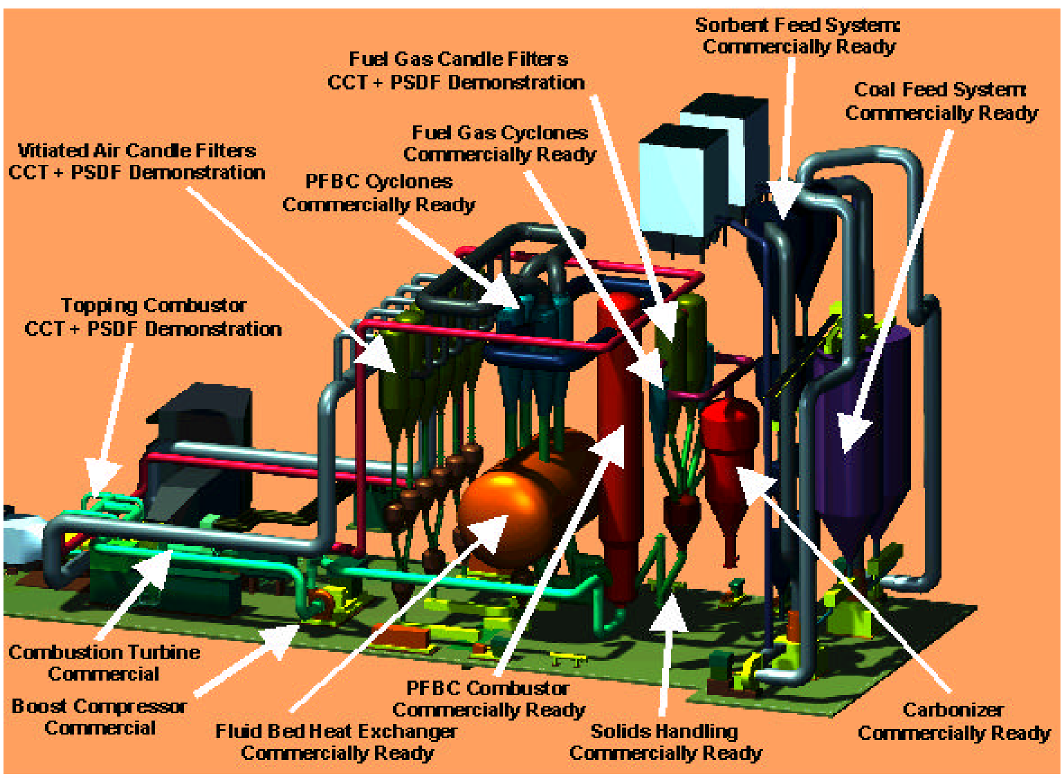


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Table 3-12
APFBC Developmental Status

Zone	Status	Issues	Resolutions
Fuel Forwarding System (Sorbent and Fuel)	Commercial	Dry feed is proven technology. Paste feed is simpler, but rotary parts wear out. Paste consistency hard to maintain.	Use existing dry feed methods; new feed concepts are under development.
Carbonizer	Demonstrated at pilot scale	Dry feed demonstrated. Paste feed bench tested. Scale-up required.	Use existing dry feed methods; new feed concepts are under development.
Char Transfer System	Demonstrated at pilot scale	No problem anticipated; requires large-scale demonstration.	Demo - PDU & CCT
PFBC Combustor	Demonstrated at pilot scale	No problem anticipated; requires large-scale demonstration.	Demo - PDU & CCT
Fluid-Bed Heat Exchanger	Demonstrated at pilot scale	No problem anticipated; requires large-scale demonstration.	Not applicable
Ash Transport System	Commercially ready	No problems anticipated.	Not applicable
Hot Gas Cleanup	CCT demonstration	Durability, bridging, drainage, filter life.	Test programs at Wakamatsu, Karhula, Wilsonville, Piñon Pine.
Topping Combustor and MASB	Full-size combustor tested	Relatively low-Btu gas from carbonizer successfully tested at UTSI; more tests to come.	Development testing at PSDF.
Combustion Turbine	Commercial version operating on natural gas	Need provision to export air and hot gas input.	Designs with easy transition to air ducts preferred.
Integrated Operation	PSDF and CCT demonstration	Long-term durability, ease of operation	PSDF and CCT

Test programs are in place for all major components, and the Wilsonville PSDF and the APFBC Clean Coal projects, described in Section 3.1.2, are directed at proving large-scale integrated commercial operation.

With the exception of the hot gas filters for the carbonizer fuel gas and for the circulating PFBC exhaust gas, all of the major components of the coal-gas PFBC power plant have either been successfully tested or are commercially available. A review of the on-going developmental programs for specific PFBC components follows:

C **Combustion Turbine**

The 50 MWe class Siemens-Westinghouse Power Corporation W251, the 120 MWe class W501DS, the 185 MWe class W501F, and the 70 MW class Siemens KWU V64.3 have designs evaluated for use in PFBC applications. In addition, the feasibility of advanced PFBC-modified versions of Pratt & Whitney FT8 Twin-Pacs, Rolls-Royce Industrial Trent, and Siemens KWU V84.3 engines have been evaluated by the manufacturers. Dresser-Rand industrial gas expanders are also being evaluated for PFBC service. All of these commercial combustion turbines require modification for PFBC operations. One of the key areas is the topping combustor containing multi-annular swirl burners providing:

– Stable combustion of the low-Btu content fuel gas,
– Combustion with low NOx formation,
– Lower oxygen content vitiated air, and
– High temperatures of the fuel gas and the vitiated air (about 1400 ^{o}F+).

Modifications to the turbine casing accommodates the plenums for collection of high-pressure compressor discharge air, and accommodates the topping combustor.

Long-term integrated operation with a PFBC system with a PFBC-modified commercial gas turbine will be demonstrated in the Lakeland McIntosh Station.

C **Pressurized Solids Handling**

Three systems in design and verification comprise the pressurized solids handling system; the fuel forwarding system, the char transfer system, and the ash transport system. The fuel forwarding system has been successfully tested using dry coal and coal paste, including on-line switching from dry coal-sorbent feed to paste feed. Paste feed uses the simplest hardware, but paste consistency is difficult to maintain.

Tests run by Foster Wheeler Development Corporation (FWDC) in September 1995 demonstrated the technical viability of the char transfer system in moving char from the reducing carbonizer to the oxidizing circulating PFBC for 120 hours without problems using screw feeders. Tests run by FWDC in 1993 demonstrated that N-Value transfer system would operate well at commercial size feed rate over 2,000 lb/hour.

C **Carbonizer, PFBC Combustor, Fluid-Bed Heat Exchanger**

PFBC Carbonizer

Tests run by FWDC in September 1995 demonstrated the technical viability of integrated carbonizer-circulating PFBC operation. Minor drain line plugging encountered during the tests were cleared during operation. Over the 120 hours of the test, feed coal was separated into fuel gas and char in the carbonizer, and the char was continuously transferred by the char transfer system from the reducing carbonizer to the oxidizing circulating PFBC, where it was burned. The tests included three coal feedstock blends:

– 3.5% sulfur petroleum coke with Plum Run dolomite;
– 3.4 percent sulfur Kentucky No. 9 coal with Three Rivers limestone; and
– 1.5 percent sulfur Pittsburgh No. 8 coal with Three Rivers limestone.

A dry-feed carbonizer will be used in the Lakeland CCT plant based upon lowest cost system.

PFBC Combustor

Early carbonizer-circulating PFBC tests were hampered by blockages in the circulating PFBC cyclone. The problem was isolated traced to poor sorbent and the cyclone loop seal. Resolution came by changing the fluidizing air at the loop seal and changing sorbents. The circulating PFB combustor has been successfully operated for hundreds of hours with both dry feed and paste feed.

Fluid Bed Heat Exchanger

The fluid bed heat exchanger has been designed and tested without problems.

C **Hot Gas Particulate Cleanup**

High-temperature ceramic filters clean fuel gas from the carbonizer and vitiated air from the PFB combustor. The hot gas cleanup system is one developmental focus of the PFBC plant test programs. Technical challenges for 1400 ºF to 1700 ºF hot gas cleanup operation include:

- – Material creep,
- – Brittle fracture,
- – Alkali destruction of binder,
- – Bridging, broken supports,
- – Blinding, and
- – Ash drain stoppage.

Hot gas filters are necessary to reach the efficiency goals of second generation and advanced PFBC. Of the five PFBC demonstration plants which have operated or are in operation, only two of them, Tidd and Wakamatsu (see Section 3.1.2), tested particulate removal devices other than cyclones. Hot gas particulate filtration, shown in Figure 3-13, using high-temperature candle filters is under test. The goal for commercial readiness is three-year candle duration, with only annual inspection.

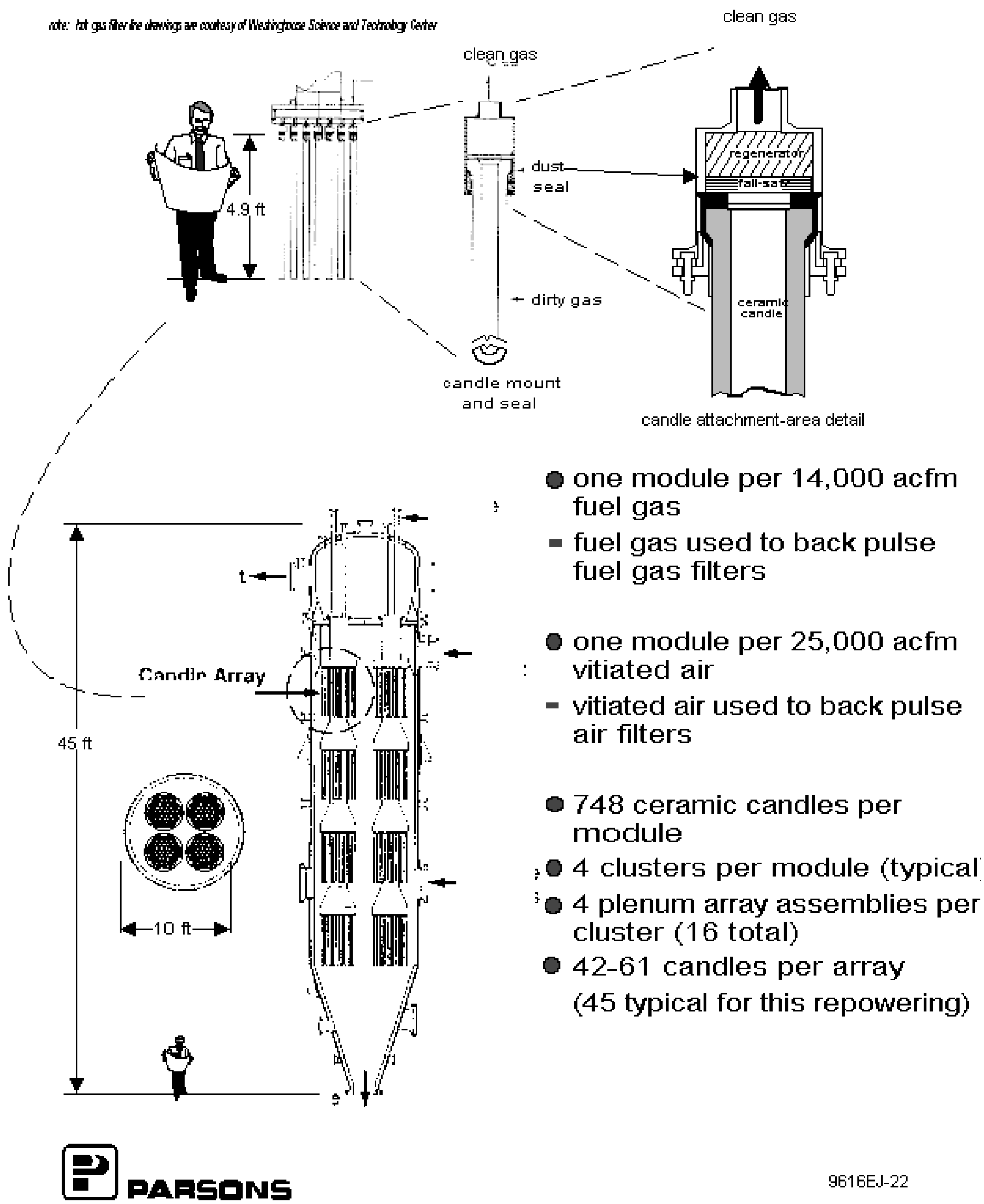
The Siemens Westinghouse Power Corporation filter systems with candle filters are planned for use in the PFBC Clean Coal Technology demonstration plant. In this proposed design, the initial configuration cools the carbonizer gas to 1400 ºF to accommodate the ceramic candle filters. As a result, the fuel gas cleanup would operate at 1400 ºF. The temperature of the circulating PFBC exhaust (and hot gas cleanup) is 1500 to 1600 ºF. These temperature profiles could change as the design develops. With the CCT PFBC plant project proceeding, a filter demonstration could be in place by 2002, which will satisfy the program goals for PFBC. This schedule, however, could be accelerated if commercial size filter vessels are tested with success at DOE's PSDF or Piñon Pine IGCC demonstration.

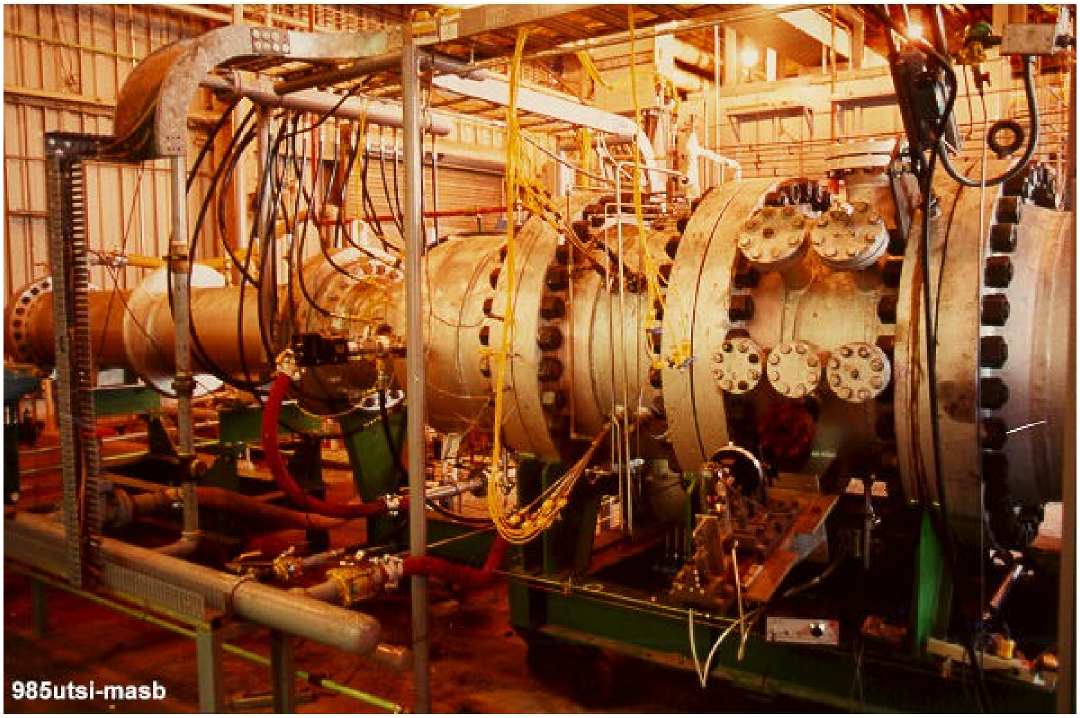
C **Topping Combustor**

Siemens Westinghouse Power Corporation and UTSI successfully designed and tested a full-scale (18-inch) low-NOx multi-annular swirl burner (MASB) with natural gas and synthetic fuel gas; see photo. This MASB is intended for use in the W251 (50 MW), W501D5 (120 MW), and W501F (185 MW) combustion turbines.

The MASB was tested with reduced excess air and fuel switching between natural gas and synthetic fuel gas. This one-year test program also includes tests with natural gas and 700 ºF inlet air, to simulate operation with both the carbonizer and PFBC out of service.

Figure 3-13
Hot Gas Particulate Filtration





Siemens Westinghouse Multi-Annular Swirl Burner Under Test at UTSI

The APFBC plant at the Wilsonville Power System Development Facility is testing the first operation of a gas turbine and topping combustor with hot (1400 ºF) pressurized fuel gas from the carbonizer and hot (1400 °F), low oxygen concentration pressurized vitiated air from the APFBC. Initial testing has led to some design modifications.

The environmental goals for PFBC address the emissions of NOx, SOx, particulates, and HAPs. All of the APFBC criteria pollutants (SO_2, NOx, particulates) show a large potential for reduction from present pulverized coal technology, and if development issues are resolved, especially with hot gas particulate control and the topping combustor, emission will meet the 2000 and 2005 goals. The 2010 goals of 1/10 NSPS will require incremental technology improvement but should be achievable. DOE also has goals that are concentrated on CO_2 capture and greenhouse gas emissions. PFBC with its high efficiency will reduce CO_2 emissions per kilowatt considerably over conventional technology.

System analyses and conceptional designs indicate advanced PFBC systems can meet the DOE 2005 and 2010 goals for PFBC if the developmental plans in place are successful. Table 3-13 illustrates the characteristics of a plant that would be commercially available after the Lakeland CCT plant has been demonstrated. The plant is a nominal 320 MWe unit incorporating a PFBC unit with a carbonizer producing a coal-derived fuel gas and char, with ceramic high-temperature, high-pressure filters operating at 1600 ºF (combustor system) and 1700 ºF (carbonizer system), and a gas turbine inlet temperature of 2300 ºF.

Table 3-13
Baseline Commercial Plant Characteristics

	Commercial Plant
Net Power Output	320 MWe
Plant Efficiency, HHV	47.3%
SO_2 Emissions	95% removal
NOx Emissions	0.10 lb/10^6 Btu
Particulates	0.002 lb/10^6 Btu
CO_2 Emissions	204 lb/10^6 Btu

Additional studies and systems analyses have been conducted by DOE to determine the efficiency that could be achieved by pushing technology limits to the known maximum boundaries (highest temperature cleanup and high-temperature advanced turbine design with supercritical bottoming cycles).

Table 3-14 illustrates the characteristics of this advanced plant that would be available after the commercial plant has been demonstrated. The plant is a nominal 320 MWe unit incorporating a PFBC unit with a carbonizer producing a coal-derived fuel gas and char, with ceramic high-temperature, high-pressure filters operating at 1600 ºF (combustor system) and 1600 ºF (carbonizer system), gas turbine inlet temperature of 2600 ºF, and supercritical steam cycle of 4500 psi with the main steam at 1100 ºF and the two reheat temperatures at 1075 ºF and 1050 ºF, respectively.

Table 3-14
Development Path Plant Characteristics

	Commercial Plant
Net Power Output	320 MWe
Plant Efficiency, HHV	51.8%
SO_2 Emissions	97% removal
NOx Emissions	25 ppm
Particulates	0.002 lb/10^6 Btu
CO_2 Emissions	204 lb/10^6 Btu

3.2.2.1 Programs Initiated to Meet the Strategic Goals

The DOE organizations that implement the development of technology, particularly the Federal Energy Technology Center, have programs that continue to advance the development and commercialization of PFBC by improving performance, economics, and environmental acceptance.

DOE programs and associated goals for PFBC have success targets that are generally classified as being in the near term or longer term. Near-term targets are based on utilization of developmental technologies that are either demonstrated or commercial, whose results are contingent on system or demonstration in the foreseeable future. Long-term PFBC goals are contingent on both development and demonstration of technologies.

Programs Initiated to Meet the Near-Term Goals

In the near term, the DOE is supporting the following PFBC testing and demonstration facilities:

- Hot Gas Particulate Removal PDU (HGPR/PDU, Karhula, Finland)
- Power Systems Development Facility (PSDF, Wilsonville, Alabama)
- CCT HGPR Demonstrations (Piñon Pine, Tampa Electric Company)
- CCT Demonstration Plant (Lakeland)

The Karhula PFBC ceramic filter test facility has been operating for a number of years. The Wilsonville PSDF began operation in 1996. The transport reactor will be initially operated at the PSDF as a pressurized fluid-bed combustor to produce a flue gas for hot gas particulate filter experiments. The CCT HGPR facilities are now undergoing startup and shakedown. The Lakeland CCT Demonstration is scheduled for startup early in the 2000 to 2010 decade. Based on these schedules, achievement of the 2005 and 2010 PFBC goals can be realized if the development programs are successful.

Studies of conceptual PFBC designs have indicated that is possible to reach plant efficiencies of over 50 percent through the successful integration of advanced combustors/carbonizers and hot gas particulate removal with advanced gas turbine technology. Utilization of advanced PFBC technology alone can result in plants meeting the 2005 and 2010 goals.

Table 3-15 is a listing of the near-term goals that are applicable to PFBC technology, with each goal matched to a current DOE initiative that would be influenced by the goal.

Table 3-15
Initiatives Supporting Near-Term Goals

Target Year	Coal and Power Systems Program Goal	Initiatives that Complement Coal and Power Systems Program Goals
2000	Develop an advanced coal-based power system capable of 42% efficiency with emissions at 1/3 NSPS, at COE comparable with conventional power plants.	CCT Demonstration ATS Development PSDF Pilot Plants Hot Gas Particulate Removal Program
2000	Develop the technology base to ensure achievement of the reduction goals for greenhouse gas emissions to which industry has agreed under the voluntary reductions program.	CCT Demonstration ATS Development PSDF Pilot Plants FETC Research
2002	Develop new technologies to meet existing and pending standards and regulations on ozone, particulate matter, and HAPs for both new and existing facilities.	PSDF FETC Research

Programs Needed to Meet the Long-Term Goals

To achieve PFBC efficiencies in the year 2010 that are consistent with the Advanced Power Systems goals for PFBC, development of a first-generation ATS, combined with hot gas cleanup, with an integrated carbonizer/combustor must be completed. To achieve the long-term goals, particularly an efficiency of greater than 60 percent HHV, it would be necessary for the next generation of ATS to be developed.

Table 3-16 is a listing of the long-term goals applicable to PFBC technology, with each goal matched to a current DOE initiative that would be influenced by the goal.

Table 3-16
Initiatives Supporting Long-Term Goals

Target Year	Coal and Power Systems Program Goal	Initiatives that Complement Coal and Power Systems Program Goals
2005	Have market-ready PFBC systems with efficiencies of 45%, emissions from 1/5 to 1/10 of present regulations, and equivalent costs.	CCT Demonstration ATS Development PSDF Pilot Plants Hot Gas Particulate Removal Program
2005	Develop technology options for cost-effective greenhouse gas capture and sequestration when used as part of a least-cost strategy for greenhouse gas management.	PSDF Pilot Plants FETC Research
2007	Complete systems configuration development of near-zero emission Advanced Power Systems.	PSDF Pilot Plants FETC Research
2008	Validate systems capable of 52% efficiency at cost lower than conventional systems, reducing CO_2 emissions by 35%, and environmental emissions less than 1/10 NSPS.	CCT Demonstration PSDF Pilot Plants FETC Research ATS Development
2009	Complete development of critical components for all Advanced Power Systems with near-zero pollutant emissions.	CCT Demonstration PSDF Pilot Plants FETC Research
2010	Develop PFBC systems with 45 to 50% efficiency, emissions less than 1/10 present regulations and costs lower than conventional systems, capable of firing a variety of coals and waste fuels.	CCT Demonstration ATS Development PSDF Pilot Plants Hot Gas Particulate Removal Program
2010	Validate all critical components and subsystems for Advanced Power Systems that can achieve over 60% efficiency with near-zero pollutant emissions. Develop new, cost-effective, advanced environmental control technologies for achieving near-zero emissions.	CCT Demonstration ATS Development PSDF Pilot Plants Hot Gas Particulate Removal Program
2010	Develop cost-effective technologies to achieve capture and sequestration of greenhouse gas emissions which integrate with advanced CCT.	CCT Demonstration PSDF Pilot Plants FETC Research

3.3 COST AND PERFORMANCE OF ADVANCED POWER SYSTEMS

The following subsections summarize cost and performance data for advanced power systems including integrated gasification combined cycle and pressurized fluidized-bed combustion. Details of the performance and cost evaluation for these technologies are provided in Sections 7.0 and 8.0 of Volume II.

3.3.1 Integrated Gasification Combined Cycle

The IGCC-based power plants discussed in Section 7.0 of this report represent a reasonable basis for projection of achievable cost and performance in the timeframe for application beginning by 2005. The plants include two examples of air-blown KRW type gasifiers (in two nominal sizes, 400 MWe and 200 MWe), and one example of an oxygen-blown Destec gasifier at a nominal size of 380 MWe. The projected cost and performance for each of these cases is presented in Table 3-17 below, based on the use of Illinois No. 6 coal.

Table 3-17
Projected Cost and Performance of Typical IGCC Plants
(In-Service Year 2005)

Gasifier	Air-Blown KRW	Air-Blown KRW	O_2-Blown Destec
Nominal size, MWe (net)	385	198	350
Efficiency, HHV, %	47.1	42.2	45.4
Heat Rate, Btu/kWh	7,247	8,086	7,526
Capital cost, 1999 $/kW	1,432	1,796	1,369
SO_2, lb/10^6 Btu	0.07	0.07	0.06
NOx, lb/10^6 Btu	0.16	0.16	0.08

The two larger plants presented in the above table, KRW-400 and Destec, are based on the use of a combustion turbine that is expected to represent the commercially available state-of-the-art in the year 2005. The Westinghouse 501G machine was modeled for this evaluation, but competitive models from other vendors would yield similar results.

The smaller KRW-200 plant utilizes the Westinghouse 501D5A machine. The differential in plant efficiency of about 4 percentage points (about 8 percent on a heat rate basis) is largely attributable to the use of the different combustion turbines. The more advanced machines provide superior thermodynamic performance.

The KRW gasifiers utilized in this study are assumed to be identical in size and configuration to the unit installed in the Piñon Pine CCT facility. For the KRW-400 case, three gasifier islands are used, operating at a higher pressure (400 psig vs. 300 psig, nominal) to provide fuel gas at sufficient pressure for the high-pressure conditions of the W501G burner section. Vessel and piping wall thicknesses are increased to compensate, so that hoop stress levels in the pressure boundary are essentially unchanged. It is assumed that mass throughputs and gas production are increased in proportion to the operating pressure without compromise to the gasification process. For the KRW-200 plant, two gasifier islands are provided, which may be considered identical to the Piñon Pine unit.

The use of multiple gasifiers, in a modular fashion, minimizes scale-up risks relative to Piñon Pine. Future application of this technology, beyond the year 2005, may utilize scale-up of the Piñon Pine gasifier modules, resulting in use of two gasifiers for the KRW-400, and possibly one gasifier for the KRW-200 conceptual design presented herein. This scale-up and reduction in the number of components would result in a reduction of plant capital costs.

The hot gas desulfurization process used in the KRW cases is an application of transport technology and a zinc titanate-based sorbent. The final stages of particulate removal in the gas cleanup train for the KRW cases are based on use of arrays of candle-type ceramic filters. Both the sulfur removal and the particulate removal represent technology applications that are projected to be state-of-the-art in the year 2005. They represent some degree of risk, from a process perspective. This risk can be mitigated by the use of more conservative design parameters, or the substitution of better established processes, which may lead to some increase in costs. These are accounted for in the process contingency estimates.

The Destec gasifier used herein represents a modest increase in scale, on the basis of tons/day of coal gasified, relative to the unit installed in the Wabash River Coal Gasification Repowering Project. The increase in electrical output, relative to Wabash River, is a consequence of the increased coal gasification rate and the increase in plant efficiency. The efficiency increase is attributable to the use of the W501G turbine in the case defined herein.

The Destec gasifier concept evaluated in this report utilizes a GE moving-bed hot gas cleanup system with zinc-based sorbent for desulfurization. The sulfur-rich regeneration gas, containing SO_2, is fed to a sulfuric acid plant, converting the SO_2 to SO_3 by catalytic reaction, followed by absorption in sulfuric acid to produce additional acid. The GE moving-bed concept is current state-of-the-art, whereas the zinc sorbent is projected to be available as state-of-the-art in the year 2005.

Particulate removal in the Destec gasifier considered relies on high-efficiency cyclones for particulate removal. The GE moving-bed desulfurizer and a chloride guard bed of nahcolite provide polishing steps to capture very small particulates that are not removed by the cyclones. The particulate removal features of this Destec design concept represent established practices, and are not considered to add to process risk.

3.3.2 Pressurized Fluidized-Bed Combustion

The PFBC-based power plants discussed in Section 8.0 of this report represent a reasonable basis for projection of achievable cost and performance in the timeframe for application beginning by 2005. The plants include two examples of circulating PFBC (one maximum power output and one maximum efficiency), and one example of a bubbling-bed PFBC. The plants are sized for a nominal 430 MWe, 380 MWe, and 425 MWe, respectively. The projected cost and performance for each of these cases is presented in Table 3-18, based on the use of Illinois No. 6 coal.

Table 3-18
Projected Cost and Performance of Typical PFBC Plants
(In-Service Year 2005)

Gasifier	Circulating PFBC Max. Output	Circulating PFBC Max. Efficiency	Bubbling-Bed PFBC
Nominal size, MWe (net)	430	380	425
Efficiency, HHV, %	45.8	47.0	40.8
Heat Rate, Btu/kWh	7,463	7,273	8,354
Capital cost, 1999 $/kW	1,086	1,126	1,262
SO_2, lb/10^6 Btu	0.23	0.23	0.23
NOx, lb/10^6 Btu	0.10	0.10	0.20

The two circulating PFBC plants presented in the above table are based on the use of a combustion turbine that is expected to represent the commercially available state-of-the-art in the year 2005. The Westinghouse 501G machine was modeled for this evaluation, but competitive models from other vendors would yield similar results.

The bubbling-bed PFBC plant utilizes the ABB ASEA Stal GT-140P.

In this version of the circulating pressurized fluid-bed technology, crushed coal is injected, along with a sorbent such as limestone, into a carbonizer vessel. The coal is subjected to a mild gasification process, with the volatile matter driven off as overheads. This gaseous product passes through a single stage of cyclones to remove most of the particulates, followed by a ceramic candle filter. The char from the carbonizer, along with the solids removed by the cyclone and filter, are passed to the CPFBC vessel where the char is combusted.

The CPFBC subsystem is comprised of the CPFBC vessel, two cyclones, three ceramic candle filters, a fluid-bed heat exchanger (FBHE), a pressure vessel containing the FBHE, and a J-valve.

The solids received from the carbonizer subsystem enter the CPFBC near the bottom of the vessel. Compressed air enters the vessel at two principal locations: primary air enters at the bottom of the vessel, with secondary air entering via an array of nozzles approximately 20 feet above a grid plate located near the bottom of the vessel. The grid plate functions as an air distributor and as a floor for the bed.

Flue gases and entrained solids leave the CPFBC vessel via two refractory-lined nozzles at the top of the vessel and pass through cyclones and candle filters. Entrained solids removed by the cyclones flow by gravity down to the FBHE. Cleaned gas leaving the filters flows to the gas turbine where it is mixed with low-Btu fuel gas from the carbonizer to support combustion in the MASB.

The FBHE is contained inside a large horizontal cylindrical pressure vessel. The FBHE is divided into three major cells: a center cell that receives solids from the cyclones, and two end cells that contain tube bundles for superheating and reheating steam from the steam turbine cycle. The solids circulate between the CPFBC, cyclones, and FBHE; they return to the CPFBC in a continuous cycle. The J-valve modulates the transfer of solids, consisting of ash, unburned carbon, and sorbent material, from the bottom of the FBHE to the CPFBC vessel.

The ceramic candle filters are vertical, cylindrical vessels with conical bottom sections, containing a number of ceramic candle elements. These candle elements are arranged into arrays, each containing a number of candle elements. The arrays are supported inside the vessel by a plenum and tubesheet arrangement, reinforced with channels. The vessel interior is lined with 9 inches of refractory. The filters are designed to provide a collection efficiency greater than 99.9 percent.

In the bubbling-bed PFBC process, crushed coal and a sulfur sorbent such as dolomite or limestone are continuously injected into the fluidized-bed combustion chamber contained within a pressure vessel. Air from the gas turbine compressor supplies combustion air and fluidizes the bed. The water-cooled surface of the bed enclosure and boiler tubes submerged in the fluidized bed are used to generate steam, which drives a conventional steam turbine generator. High-pressure flue gases from the combustion process pass through high-efficiency cyclones, which remove nearly all of the particulate. This cleaned, high-pressure gas drives a ruggedized gas turbine that generates power and drives a high-pressure compressor for air delivery. The flue gas then passes through an economizer, baghouse, and finally to the stack.

The systems in a PFBC plant use conventional, proven technology. The P-800 system that forms the basis for the reference plant design is a larger version of the P-200 design that was used for the demonstration plant at Tidd and is in operation in other parts of the world. The P-800 uses multiples of the P-200 components, arranged such that three complements of heat transfer surface derived from the P-200 are placed inside the single P-800 pressure vessel. The P-800 operates at one and one-third times the pressure of the P-200 unit. At this higher pressure, three P-200 component sets are able to handle four times the air mass flow and heat transfer, yielding four times the power output.

The combustor assembly consists of the pressure vessel together with the installed internals. The main internal systems are described separately. The function of the combustor assembly is to provide the main pressure containment for the boiler, cyclones, bed reinjection, ash coolers, and bed preheating systems. The combustor assembly also prevents heat losses from the process to the environment, facilitates a good arrangement, and provides support for the internals.

A design feature of PFBC units is their modularized components, which can reduce project costs and site erection span time. The degree of modularity can be tailored to suit each PFBC plant site. The combustor internal equipment, such as platforms, boiler, cyclones, and bed reinjection vessels, are prefabricated and shop assembled into modules for field installation into the pressure vessel to the maximum extent practical. Other components such as instrumentation and insulation may be partially shop assembled, with the remaining assembly performed at the site. Service openings and manholes are provided for access during inspection, repair, or replacement of equipment, which must be carried out during normal maintenance.

The PFBC boiler contains the combustion process and absorbs the heat necessary to control bed temperature while also providing steam to the steam turbine and hot gases to the gas turbine. The boiler is a once-through design consisting of a water-cooled membrane wall enclosure and in-bed heat transfer surface.

4.0 ECONOMIC AND FINANCIAL ANALYSIS

Capital cost, production cost, and cost of electricity (COE) estimates were developed for the conceptual level advanced Clean Coal Technology (CCT) and competitive, (mature commercial) power systems described in Sections 7.0 through 10.0 of this report. The methodology employed to develop costs and economics is described in Section 4.1. The approach taken follows traditional technology screening methods of determining a revenue requirement COE based on the power plant costs and assumed financing structure. Also, it is assumed that the initial application of advanced power generators will be in a base load duty cycle. Variations in capacity factor and other sensitivities are examined for COE sensitivity. As the competitive electric market develops, power generators are "market driven," where the value of the generation assets is based on the expected cash flow from operation. In this case, follow-on versions of this evaluation guide would address the competitive environment and dispatching, with focus on return on investment and market-based pricing.

A summary comparison of the results is provided in Section 4.2 for the power systems under evaluation. Sensitivity analyses in Section 4.3 show the effect of capacity factor, heat rate, capital cost, and production cost changes on project economics. To enhance the sensitivities, limits of capacity factor and heat rate were developed from production costing modeling based on dispatching requirements for a typical utility system. Variations in fuel escalation rates are presented as a sensitivity to production costs for both coal and natural gas. In developing capital cost variations, a risk assessment model, Range Estimating Program (REP), was used to quantify the risk associated with the process contingency assigned to the capital cost estimates (see Section 3.2). The model elements for REP analysis are the major areas of technology component risk in the estimate and are used to establish contingencies and corresponding levels of risk.

The development of capital costs is influenced by the various stages of the specific technology commercial maturity. The PC and NGCC plants are representative of N^{th} unit, or fully mature plants. However, IGCC and PFBC are still considered an emerging technology, and for the purposes of capital cost determination presented in this study, are assumed to represent "initial commercial offerings." Established procedures do not exist to estimate the difference between initial commercial units and the N^{th} plant costs of a fully mature IGCC or PFBC with a similar level of accuracy as commercial PC or NGCC plants. It can be expected that mature costs will not be fully realized until several generators have been constructed and are operational, as shown in Figure 4-1. Reductions in cost from the initial commercial offerings are expected due to lower cost and/or improved materials and construction methods, and economies-in-scale in the manufacture of plant components.

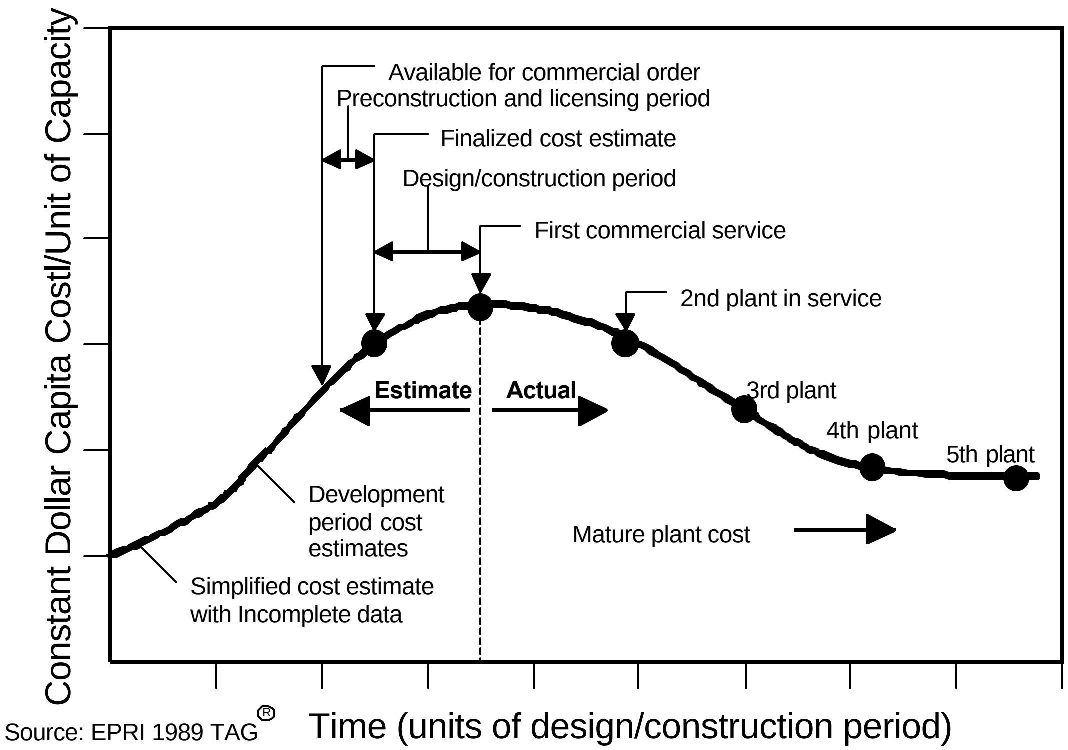


Figure 4-1
Technology Cost Development to Commercial Maturity

4.1 ASSESSMENT METHODOLOGY

The economics of the various power plants were developed on a consistent basis by determining the capital and production costs on an equivalent basis and then calculating a COE as the figure-of-merit evaluation criterion. The conceptual cost estimates were developed from several data reference sources including detailed cost summaries from a 500 MWe PC fossil plant recently constructed, a major architect/engineer's PC Reference Plant[(35)], and the DOE power plant estimates prepared as part of the Clean Coal Technology Demonstration Program.[(36)]

The emphasis of this effort was placed on obtaining reliable and creditable cost results at the total plant cost (TPC) and operation and maintenance (O&M) level. Costs for emerging technology components are based on manufacturer data for present equipment modified to reflect lessons learned from the CCT demonstrations. Results are formatted to allow a decision-maker to modify inputs and values to fit the specific needs of the market served. Detailed cost breakdowns were prepared using a consistent set of cost accounts providing ease of comparison.

The capital costs at the TPC level include equipment, materials, labor, indirect construction costs, engineering, and contingencies. Operation and maintenance cost values were determined on a first-year basis and subsequently levelized on the basis of a 20-year plant book life to form a part of the economic analysis. Quantities for major consumables such as fuel and sorbent were taken from technology-specific heat and mass balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data. Operation cost was determined on the basis of number of operators. Maintenance costs were evaluated on the basis of requirements for each major plant section. Operating and maintenance costs were then converted to unit values of $/kW-year or $/kWh.

The capital and operating cost results for each generating plant are combined with plant performance in the comprehensive evaluation of the COE.

The following general economic assumptions were used to determine plant economics:

- Plant book and tax life is 20 years.
- Capacity factor is 85 percent.
- Plant in-service date is January 2005.
- COE is determined on a levelized, tenth year constant dollar basis.
- Evaluations were performed on a market-based financing basis.

4.1.1 Methodology

This section describes the approach, basis, and methods that were used to perform capital and operating cost evaluations of the various power plant options. Included in this section are descriptions of:

- Capital Costs (Section 4.1.2)
  - Bare Erected Cost (Section 4.1.2.1)
  - Total Plant Cost (Section 4.1.2.2)
  - Total Capital Requirement (Section 4.1.2.3)
  - Capital Cost Estimate Exclusions (Section 4.1.2.4)
  - Scaling of Capital Costs (Section 4.1.2.5)
  - Regional Adjustment of Capital Costs (Section 4.1.2.6)

- Production Costs and Expenses (Section 4.1.3)
  - Operating Labor (Section 4.1.3.1)
  - Maintenance (Section 4.1.3.2)

  - Consumables, including fuel costs (Section 4.1.3.3)

- Cost of Electricity (Section 4.1.4)

The capital costs, operating costs, and expenses were established consistent with the plant scope detailed in Sections 7.0 through 10.0. Each major component was estimated using a bottoms-up approach, establishing a basis for subsequent comparisons and easy modification as the technology is further developed.

- Total plant cost, or "overnight construction costs" values are expressed in January 1999 dollars.

- Total plant investment values are expressed in mixed year dollars for a January 2005 commercial operation.

- The estimates represent commercial technology plants, or Nth plants for the PC and NGCC and initial commercial offerings for the IGCC and PFBC.

- The estimates support a complete power plant facility with the exception of the exclusions listed in Section 4.1.2.4.

- The estimate boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system but terminating at the high voltage side of the main power transformers.

- Site is characterized to be located in Middletown, USA. Although not specifically sited within any region, it is based on a relative equipment/material/labor factor of 1.0 and is considered to be located on a major navigable waterway.

- Costs are grouped according to a process/system oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

- The basis for the costs of equipment, materials, and labor is described in Section 4.1.2.

- Design engineering services, including construction management and contingencies basis, are examined in Section 4.1.2.2.

- The operating and maintenance expenses and consumable costs were developed on a quantitative basis:

- Operating labor cost was determined on the basis of the number of operators required.

- Maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost.

- Cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

- Byproduct credits for commodities such as sulfuric acid are included to cover cost of equipment. However, credits for commodities such as gypsum, and emission credits are not considered due to the variable marketability.

Each of these expenses and costs is determined on a first-year basis and subsequently levelized through application of a levelizing factor to determine the equivalent tenth year value that forms a part of the economic evaluation. This amount, when combined with fuel cost and capital charges, results in the figure-of-merit, COE.

4.1.2 Capital Costs

The capital cost, specifically referred to as total plant cost (TPC) for each power plant, was estimated for the categories consisting of bare erected cost, engineering and home office overheads, and fee plus contingencies. The TPC level of capital cost is the "overnight construction" estimate. The capital cost was determined through the process of estimating the cost of every significant piece of equipment, component, and bulk quantity. A code of accounts was developed to provide the required structure for the estimates. The code facilitates the consistent allocation of individual costs that were developed and will serve as the basis for future evaluation of other clean coal sponsored technologies and permit future cost comparisons, if desired. The code facilitates recognition of estimated battery limits and the scope included in each account. The summary level of this code, typical for an IGCC plant, is presented as Table 4-1. The detail level of the code is included in Appendix B.

Table 4-1
Code of Direct Accounts Summary

Account Number	Account Title
1	Coal and Sorbent Handling
2	Coal and Sorbent Preparation and Feed
3	Feedwater and Miscellaneous (BOP) Systems and Equipment
4	Gasifier and Accessories
5	Hot Gas Cleanup and Piping
6	Combustion Turbine and Auxiliaries
7	Heat Recovery Steam Generator, Ducting and Stack
8	Steam Turbine Generator and Auxiliaries
9	Cooling Water System
10	Ash/Spent Sorbent Recovery and Handling
11	Accessory Electric Plant
12	Instrumentation and Control
13	Improvements to Site
14	Buildings and Structures

The capital cost is defined not only in terms of the TPC but also the categories of bare erected cost (BEC), total plant investment (TPI), and total capital requirement (TCR). Table 4-2 identifies the various cost elements that are included in each level of the capital cost.

4.1.2.1 Bare Erected Cost

The bare erected cost level of the estimate, also referred to as the sum of process capital and general facilities capital, consists of factory equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs.

Table 4-2
Levels of Capital Cost

Bare Erected Cost (Process Capital and Facilities)
    Equipment Cost
    Material Cost
    Direct Labor Cost
    Indirect Labor Cost

Total Plant Cost (TPC)
    Engineering
    Contingencies
        Process
        Project

Total Plant Investment (TPI)
    Cash Expended (Escalation)
    AFDC

Total Capital Requirement (TCR)
    Royalty
    Preproduction Cost
    Inventory Capital
    Initial Catalyst and Chemicals
    Land Cost

The reference cost basis for major equipment prices was primarily vendor-furnished and adjusted vendor cost data supplemented by other budget cost information. These include:

- Coal and sorbent handling
- Coal and sorbent preparation and feed
- Feedwater and miscellaneous BOP systems
- Steam generator and related equipment
- Flue gas cleanup
- Combustion turbine generator
- HRSG, ducting and stack
- Steam turbine generator
- Batteries
- Condenser
- Vacuum pump
- Cooling tower
- Feedwater heater
- Deaerator
- Demineralizers
- Stack
- CEMS
- Transformers
- Balance of plant
- UPS

Other process equipment, minor secondary systems, and materials were estimated on the basis of the PC reference plant,[9] catalog data, and standard utility unit cost data. The piping system costs for the advanced power plants were estimated on the basis of in-house estimates of the same technology and were supplemented with costs from corresponding systems in the PC reference plant. The electrical and instrument and control (I&C) portions of the estimates were developed using material and equipment types and sizes typically used to construct a domestic utility owned and operated power plant.

In most cases the costs for bulk materials and major electrical equipment for the reference estimates were derived from recent vendor or manufacturer's quotes for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not well defined, requirements were assumed and estimated using historical cost data. Areas such as cable and raceway, lighting, paging, heat tracing, and unit heating were estimated based on project experience for a plant of comparable size with enclosed boiler and turbine buildings in a climate range similar to that of the proposed general location of this plant. Grounding for the project is included in the estimate assuming that a design for a loop type system attached to ground pads on structural steel and installed in slabs will be the accepted method. The section of the estimate for the distributed control system was developed from a system specified and designed for a plant of comparable capacity(14). The cabling for this system is included in the bulk cable portion of the estimate.

Although not specifically sited within any region, it is based on a relative equipment/material/labor cost factor of 1.0. Specific regional locations would result in adjustments to these cost factors. The reference labor cost to install the equipment and materials was estimated on the basis of labor manhours. Labor costing was determined on a multiple contract labor basis with the labor cost including direct and indirect labor costs plus fringe benefits and allocations for contractor expenses and markup. This was supplemented in limited cases, as required, with equipment labor relationship data to determine the labor cost. The relationships used were based on the A/E data and the source plants.

The indirect labor cost was estimated at 7 percent of direct labor to provide the cost of construction services and facilities not provided by the individual contractors. The indirect cost represents the estimate for miscellaneous temporary facilities such as construction road and parking area construction and maintenance, installation of construction power; installation of construction water supply and general sanitary facilities, and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items.

4.1.2.2 Total Plant Cost (TPC)

Total Plant Cost (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. The engineering costs represent the cost of architect/engineer (A/E) services for home office engineering, design, drafting, and project construction management services. The cost was determined at a nominal rate of 8 percent for all balance of plant and 12 percent for the CCT technology portions of the plant. These percentages were applied to the bare erected cost on an individual account basis. Any cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Allowances for contingencies are also considered as part of the TPC. Since the advanced power systems are in the development and demonstration stage, process contingency was added to the estimated cost of systems considered in the development phase of commercial maturity. In addition, project contingency was included as part of the TPC cost. The general basis for assessing contingencies is identified below and the process and project contingency rates at the summary level are identified in Appendix B.

Consistent with conventional power plant practices, the general project contingency was added to the total plant cost to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. This project contingency is intended to cover the uncertainty in the cost estimate itself. The contingencies represent costs that are expected to occur. Based on commercial experience and EPRI guidelines [8], a variable project contingency with a range of values between 5 percent and 30 percent was applied to the individual accounts to arrive at the plant nominal cost value. The basis for the process contingency is addressed in Section 3.2, Risk Assessment.

Tables 4-3a and 4-3b provide cost results at the summary level of the code of accounts for each component of TPC. Sections 7.0 through 10.0 contain the estimate category listing in the same format as those tables.

Table 4-3a
Case Comparison - Cost Data
Total Plant Cost (Jan., 1999 $)

Acct		IGCC - KRW x 3		IGCC - KRW x 2		Destec IGCC		NGCC "G"		Supercritical PC	
No.	Item/Description	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW
1	COAL & SORBENT HANDLING	33,497	87	23,700	120	25,228	72			31,402	78
2	COAL & SORBENT PREP.& FEED	20,161	52	13,065	66	23,766	68			12,077	30
3	FW, COND. & MISC. SYS.	20,307	53	12,540	63	18,375	53	19,924	62	27,250	67
4	GASIFIER & ACCESSORIES	114,454	297	79,755	403	129,039	371			83,753	207
5	HOT GAS CLEANUP & PIPING	132,658	345	78,639	397	59,666	171			71,217	176
6	COMBUSTION TURBINE/ACCESSORIES	67,470	175	38,445	194	65,390	188	46,628	144		
7	HRSG, DUCTING & STACK	22,946	60	14,190	72	23,702	68	22,690	70	27,247	67
8	STEAM TURBINE GENERATOR	31,401	82	19,293	97	26,884	77	21,460	66	67,799	168
9	COOLING WATER SYSTEM	13,409	35	8,622	44	11,638	33	9,576	30	25,125	62
10	ASH/SPENT SORBENT HANDLING SYS	17,291	45	11,361	57	10,088	29			23,700	59
11	ACCESSORY ELECTRIC PLANT	24,833	65	17,627	89	33,057	95	17,407	54	26,254	65
12	INSTRUMENTATION & CONTROL	17,059	44	13,287	67	16,762	48	15,919	49	15,910	39
13	IMPROVEMENTS TO SITE	9,839	26	7,100	36	9,676	28	8,821	27	9,958	25
14	BUILDINGS & STRUCTURES	14,199	37	10,499	53	13,320	38	11,962	37	45,830	113
	TOTAL PLANT COST	$539,525	$1,402	$348,123	$1,757	$466,594	$1,340	$174,386	$539	$467,524	$1,157

Table 4-3b
Case Comparison - Cost Data
Total Plant Cost (Jan., 1999 $)

Acct		BB PFB (P800)		2gPFB (+Efficiency)		2gPFB (+Power)		NGCC "G"		Supercritical PC	
No.	Item/Description	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW	$x1,000	$/kW
1	COAL & SORBENT HANDLING	39,084	92	34,266	90	37,538	87			31,402	78
2	COAL & SORBENT PREP.& FEED	45,412	107	25,153	66	27,493	64			12,077	30
3	FW, COND. & MISC. SYS.	29,636	70	21,720	57	25,128	58	19,924	62	27,250	67
4	GASIFIER & ACCESSORIES	121,479	286	71,463	189	87,349	203			83,753	207
5	HOT GAS CLEANUP & PIPING	23,130	54	37.503	99	37,672	87			71,217	176
6	COMBUSTION TURBINE/ACCESSORIES	62,755	148	80,965	214	81,074	188	46,628	144		
7	HRSG, DUCTING & STACK	2,949	7	16,210	43	16,236	38	22,690	70	27,247	67
8	STEAM TURBINE GENERATOR	61,283	144	35,463	94	43,237	100	21,460	66	67,799	168
9	COOLING WATER SYSTEM	22,274	52	14,127	37	16,665	39	9,576	30	25,125	62
10	ASH/SPENT SORBENT HANDLING SYS	25,292	60	11,914	31	12,832	30			23,700	59
11	ACCESSORY ELECTRIC PLANT	28,509	67	25,851	68	27,634	64	17,407	54	26,254	65
12	INSTRUMENTATION & CONTROL	32,168	76	17,262	46	17,948	42	15,919	49	15,910	39
13	IMPROVEMENTS TO SITE	13,817	33	13,048	34	13,863	32	8,821	27	9,958	25
14	BUILDINGS & STRUCTURES	16,608	39	12,602	33	13,751	32	11,962	37	45,830	113
	TOTAL PLANT COST	$524,396	$1,235	$417,545	$1,102	$458,419	$1,063	$174,386	$539	$467,524	$1,157

Total Plant Investment (TPI)

In addition to the TPC cost level, the TPI was developed to determine TCR. TPI at date of startup includes escalation of construction costs and allowance for funds used during construction (AFDC), formerly called interest during construction, over the construction period. TPI is computed from the TPC, which is expressed on an "overnight" or instantaneous construction basis. For the design and construction cash flow, a variable expenditure rate was assumed, with all expenditures taking place at the end of the year. Based on present market experience, the design and onsite construction periods have seen significant reductions from traditional utility practice. The design/construction periods for the technologies considered in this study have been estimated as follows:

- 40 months for the 400 MW KRW IGCC plant.
- 36 months for the KRW 200 MW IGCC and PC plant.
- 33 months for the PFBC plants.
- 33 months for the Destec entrained IGCC plant.
- 27 months for the combustion turbine combined cycle plant.

The value of escalation, escalated cost, is determined by adjusting the capital costs from the overnight basis of TPC to the cost value in the year of expenditure and summing these values to arrive at the value titled total cash expended (TCE). This TCE value for each technology is shown on the Capital Investment & Revenue Requirement Summary in Appendix B. Since the economic results in this guide include a constant dollar analysis, the TCE is equal to the TPC. The escalated annual values serve as the basis for the determination of AFDC. This cost represents the total interest incurred from the time of expenditure until the plant is placed in service.

In the evaluations presented in this guide, the debt and equity rates, with the constant dollar basis, do not include general inflation. The calculated AFDC and the capital structure used to determine interest are included on the Capital Investment & Revenue Requirement Summary and the Estimate Basis/Financial Criteria for Revenue Requirement Calculations for each technology, which are included in Appendix B. When current dollars are used as the basis or when the year of inservice is greater than in this evaluation, the TCE value will be greater. Unless a longer construction schedule is utilized, the AFDC will not change significantly for a later inservice date except for the impact of higher escalated costs as the basis for calculation. Also, if the AFDC rate is different from the weighted cost of capital, the calculated cost of AFDC will be markedly changed.

For the purposes of this evaluation guide, the cash flow requirements for each technology were determined on an annual basis. If a procurement and construction schedule were utilized as the basis for the cash forecast, the accuracy of the calculation of both escalation and AFDC would be increased. This increase in accuracy would be due to the ability to determine cash flow values on a quarterly or monthly basis. The forecast utilized in the guide is based on the technology design/construct duration supplemented by 6 to 12 months of pre-engineering activity. The annual percentages, values, and AFDC for each technology are shown in Appendix B. Given TPC, cash flow assumptions, nominal interest, and escalation rates, TPI was calculated using:

- Weighted cost of capital, 6.4 percent on a constant dollar basis (refer to Appendix B for details of the capital structure which define the weighted cost of capital).

- Inflation rate, 0.0 percent, constant dollars with zero real escalation.

4.1.2.3 Total Capital Requirement (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, preproduction (or startup) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. They are estimated as follows:

  – One month fixed operating costs -- operating and maintenance labor, administrative and support labor, and maintenance materials.

  – One month of variable operating costs at full capacity (excluding fuel) -- includes chemicals, water, and other consumable and waste disposal charges.

  – Twenty-five percent of full capacity fuel cost for 1 month -- covers inefficient operation that occurs during the startup period.

  – Two percent of TPI -- covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.

- Inventory capital is the value of inventories of fuel, other consumables, and byproducts, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows: solid fuel inventory is based on full-capacity operation for 30 days, but natural gas is excluded from inventory capital. Inventory of other consumables (excluding water) is normally based on full-capacity operation at the same number of days as specified for the fuel. In addition, an allowance of 1/2 percent of the TPC equipment cost is included for spare parts.

- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not on storage, which is covered in inventory capital). No value is shown because costs are minimal and included directly in the component equipment capital cost.

- Land cost is based on 300 acres for the 400 MW IGCC, PFBC, and PC plants, 225 acres for a 200 MW plant, and 100 acres for the NGCC plant at $1,500 per acre.

Owner's Costs

Plant owner's costs are, in general, not included in the capital cost estimates, although there are several exceptions. With reference to the Capital Investment & Revenue Requirement Summaries included in Appendix B and as indicated, some owner's costs are included in the total capital requirement (TCR). Preproduction costs are a TCR line item estimate of the operating expenses to start up and place the unit in service. Inventory capital, sometimes called working capital, is the estimate of initial plant inventories; the value includes an allowance for spare parts. Land cost is estimated and includes the cost directly associated with land acquisition. This land cost allowance is based on a generic cost per acre and could vary considerably due to site size constraints or the cost of land for a designated site. Other potential owner's costs such as developer fees and expenses, permitting, and owner's costs during construction are not included in the estimates.

The estimates in this guide could be supplemented for some or all of the excluded owner's costs. These values would normally be included in place of the Initial Catalyst & Chemicals and supplementing the Land Cost categories on the Capital Investment & Revenue Requirement Summaries found in Appendix B.

Turnkey Cost Estimate

The conceptual capital cost estimates in this guide were developed to reflect market-based economics in an unregulated utility environment. Another class of capital cost estimate includes engineering, procurement, and constructing (EPC) cost. As the name implies, the scope includes 11 activities required to perform engineering, procurement, and construction of the complete power plant. The major distinction in this type of project and the corresponding estimate is that a greater portion of the cost and performance risk is borne by the contractor rather than the owner. From an owner's perspective, the EPC offers the advantages of lower capital cost, easier acquisition of financing, less risk, and shorter project schedule. These advantages are tempered by the disadvantages of less flexibility of project scope, less control of design and construction, higher costs to change the design, and a greater effort required to prepare design specifications and the request for proposal (RFP).

The EPC project requires a site-specific estimate based on a clearly defined scope of work. This estimate also requires extensive vendor quotes on equipment, detailed bulk quantity estimates that reflect the site location and accurate local labor evaluation. In addition, the EPC estimate should include consideration for indirect costs such as insurance bonds, liquidated damages, agent fees, and developer expenses. While the estimates in this guide are nominally accurate to +/- 15 percent, the EPC estimate is generally closer to a +/- 5 percent accuracy. Along with the increased accuracy of the estimate, the contingency for EPC would be significantly less than the 14.5 to 17.5 percent project contingency of the CCT plants or the 12.2 to 14 percent contingency for the conventional plants. This higher quality estimate for EPC projects is necessary since the results form the basis for the price of a legally binding agreement.

The estimates in this guide could be adjusted to provide conceptual estimates of EPC equivalent cost. Use of the location adjustments identified in Section 4.1.2.6 could approximate the cost impact on bulk material and construction labor. This step would not accommodate actual scope differences for site-specific variances. The additional indirect costs identified above could be added with those costs added to the TPI to arrive at the TCR level of cost (refer to the Capital Investment & Revenue Requirement Summaries, Table 4-2).

4.1.2.4 Capital Cost Estimate Exclusions

Although the estimate is intended to represent a complete power plant, there are several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- Onsite fuel transportation equipment (such as barge tug, barges, yard locomotive, bulldozers) is not included.

- Allowances for site-specific conditions (such as piling, extensive site access, excessive dewatering, and extensive inclement weather) are not included.

- Switchyard (transmission plant) is not included. The scope of the cost estimate includes the high voltage terminal of the main power transformer.

- Ash disposal facility is excluded, other than the storage in the ash-storage silos. (The ash disposal cost is accounted for in the ash disposal charge as part of consumable costs.)

- Royalties are not included.

- Exclusions as identified in the preceding text.

4.1.2.5 Scaling of Capital Costs

The concept of the use of scaling factors to adjust the capital cost of power plants is well recognized. Also generally accepted is the concept of the 6/10th factor or the "6/10th rule" as the universal or default factor for scaling. However, there is a wide range of exponents applicable to power plants and power plant systems as well as factor variation within size ranges. In addition, there is the variability of the appropriate parameter for the component, system, or plant subjected to scaling in order to arrive at the equivalent cost for a different size. While these considerations suggest that the approach to scaling power plant costs ranges from simplistic to very complex, the approach suggested in this guide, to adjust the capital costs of different technologies, is sufficient to produce reasonable results.

A general rule for scaling the capital costs in this guide begins with the suggestion to use a scale exponent of 0.7 to adjust the capital cost of the various technologies. Use of this exponent can be adjusted, especially if experience supports use of alternate values. The suggested exponent can be applied to all of the technologies although there are other considerations. Scaling on the basis of the gross megawatts would be preferable to net megawatts if an estimate of gross megawatts is available. The 0.7 exponent is, for example, appropriate for the total plant of pulverized coal technology. The exponent is based on application at the total plant cost (TPC) level of costs (bare erected cost plus engineering and construction management plus contingencies). An example of this methodology is shown in Appendix B.

This approach can be utilized for the technologies in this guide to establish approximate scaled TPC costs of different sized plants. The accuracy with this approach will not be comparable to the reference values in the report, but it provides a method to approximate the cost of plants at sizes other than the reference sizes.

4.1.2.6 Regional Adjustment of Capital Costs

TPC values for each of the technologies in this evaluation guide were determined on the basis of a generic U.S. location (Middletown, USA) with a relative labor/equipment/material cost base of 1.0. With the use of location factors, as shown in Table 4-4, these costs can be adjusted to reflect regional cost impacts in other general locations. These adjustments will not address possible changes that could occur in the design as a result of alternate location, such as change in fuel, change in performance due to ambient differences, or change in design of equipment and structures for changes in climate. Although there are a wide variety of sources to define regional adjustments, the basis defined by EIA[1] EMM Region was selected.

Table 4-4
Regional Adjustment Factors

EMM Region	Factory Equipment	Site Material	Site Labor
NE	1.09	1.08	1.33
NY	1.09	1.08	1.33
MAAC	1.01	0.97	0.97
STV	0.95	0.93	0.69
MAPP	1.01	1.00	1.03
ECAR	1.01	1.00	1.03
MAIN	1.01	1.00	1.03
SPP	1.03	1.00	0.98
RA	1.05	1.03	1.02
NWP	0.99	1.00	1.2
FL	0.90	0.80	0.7
CNV	1.01	1.01	1.45
ERCOT	1.02	0.98	0.89

Source: U.S. Department of Energy/Energy Information Agency

A key to the title and geographic area for each of these regions is included in Appendix B.

4.1.3 Production Costs and Expenses

The production costs or operating costs and related maintenance expenses (O&M) described in this section pertain to those charges associated with operating and maintaining the power plants over their expected life. The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
  - Material
  - Labor
- Administrative and support labor
- Consumable
- Fuel cost

These costs and expenses are estimated on a reference year, January 1999 basis and then escalated to a first-year basis, in January 2005 dollars. The first-year costs assume normal operation and do not include the initial startup costs (refer to Section 4.1.2.3). The operating labor, maintenance material and labor, and other labor-related costs are combined and then divided into two components: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. The first-year operating and maintenance cost estimate allocation is based on the plant capacity factor.

The other operating costs, consumables and fuel, are determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis. The inputs for each category of operating costs and expenses are identified in the succeeding subsections, along with more specific discussion of the evaluation processes.

4.1.3.1 Operating Labor

The cost of operating labor was estimated on the basis of the number of operating jobs (OJ) required to operate the plant (on an average-per-shift basis). The operating labor charge (OLC) expressed in first year \$/kW was then computed using the average labor rates:

$$\text{OLC} = \frac{(\text{OJ}) \times (\text{labor rate} \times \text{labor burden factor}) \times (8760 \text{ h/y})}{(\text{net capacity of plant at full load in kW})}$$

The operating labor requirements were determined on the basis of representative data from existing plants for the major plant sections (such as coal handling and steam turbine plant). These data were combined to arrive at total plant operating requirement. The basis of the operating labor cost, rates and OJ, are identified in Appendix B.

4.1.3.2 Maintenance

The development of the maintenance labor and maintenance material costs is interdependent. Annual maintenance costs are estimated as a percentage of the installed capital cost. The percentage varies widely, depending on the nature of the processing conditions and the type of design.

On the basis of referenced data and EPRI guidelines[8,35] for determining maintenance costs, representative values expressed as a percentage of system cost were specified for each major system. The rates were applied against individual estimate values. Using the corresponding TPC values, a total annual (first-year) maintenance cost was calculated, including both material and labor components. The percentage rates for determining the maintenance costs are summarized at the capital cost summary level in Appendix B.

Since the maintenance costs are expressed as maintenance labor and maintenance materials, a maintenance labor/materials ratio of 40:60 was used for this breakdown. The operating costs, excluding consumable operating costs, are further divided into fixed and variable components. Fixed costs are essentially independent of capacity factor and are expressed in \$/kW-y. Variable costs are incremental, directly proportional to the amount of power produced, and expressed in mills/kWh (\$/MWh). There has been a strong correlation between the plant capacity factor and the fixed and variable operating cost ratio. The capacity factor is the determinant in allocating O&M cost between the fixed and variable portion for reporting purposes. The equations for these calculations are:

$$\text{Fixed O\&M} = \text{Capacity Factor (CF)} \times \text{Total O\&M (\$/kW-y)}$$

$$\text{Variable O\&M} = \frac{(1 - \text{CF}) \times \text{Total O\&M (\$/kW-y)} \times 100 \text{ cents/\$}}{(\text{CF} \times 8760 \text{ h/y})}$$

The resulting costs for O&M are shown on the Capital Investment & Revenue Requirement Summaries in Appendix B.

4.1.3.3 Consumables

The feedstock and disposal costs are those consumable expenses associated with power plant operation. Consumable operating costs are developed on a reference year basis, escalated to a first-year basis, and subsequently levelized over the 20-year life of the plant. The consumable category consists of water, chemicals, other consumables, and waste disposal.

The water component pertains to the acquisition charge for water required for the plant steam cycle and for miscellaneous services.

The chemicals component consists of:

- A composite water makeup and treating chemicals requirement in which unit cost and the ratio of chemicals to water were based on data from comparable plants.
- The liquid effluent chemical category, representing the composite chemical requirement for wastewater treating, in which unit cost and quality were developed similar to the water makeup and treating chemicals.
- The limestone sorbent cost.
- Sulfur removal and recovery catalysts.

The other consumable component consists of startup fuel, gases (primarily the nitrogen required for transport and blanketing), and steam, but does not contain any significant quantities. The waste disposal component pertains to the cost allowance for off-site disposal of plant solid wastes.

The coal fuel cost (FC) was developed on the basis of delivered coal at $1.27/10^6 Btu, based on the EIA's 1999 Annual Energy Outlook[(1)], the plant net heat rate Btu/kWh (HR), and the coal higher heating value (HHV) of 11,666 Btu/lb. For the coal as well as for all feedstock and disposal costs, the quantity per day represents the 100 percent capacity requirement, while the annual cost values are adjusted for the designated 85 percent plant capacity factor. The calculation of reference-year fuel cost occurred as follows:

- $\text{Fuel (ton/day)} = \dfrac{\text{HR x kW (plant new capacity) x 24 hours}}{\text{HHV x 2000 lb/ton}}$

- $\text{Fuel Unit (per ton) Cost} = \dfrac{\text{HHV x 2000 lb/ton x FC}}{1 \text{ x } 10^6 \text{ Btu}}$

- Fuel Cost (reference year) = Fuel (ton/day) x Fuel Unit Cost ($/ton) x 365 days x 0.85 (capacity factor)

For the NGCC plant, the natural gas price of $2.76 per million Btu was utilized. The escalation rates used in the evaluation of COE were based on the EIA's 1999 Annual Energy Outlook[(1)]. For the evaluation, a real escalation rate of -1.34 percent per year, 1999 to 2005 and -1.35 percent over book life was utilized. For the natural gas, a rate of +1.07 percent, 1999 to 2005 and +0.65 percent over book life was used.

4.1.4 Cost of Electricity (COE)

The revenue requirement method of performing an economic analysis of a prospective power plant has been widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared to various alternatives. The revenue requirement figure-of-merit utilized in this guide is the tenth year coal pile-to-busbar COE expressed in cents/kWh. The value includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), levelized fixed and variable operating and maintenance costs, levelized consumable operating costs, and the levelized fuel cost.

The levelized carrying charge, applied to TCR, establishes the required revenues to cover return on equity, interest on debt, depreciation, income tax, property tax, and insurance. Levelizing factors are applied to the first year fuel, O&M costs, and consumable costs to yield tenth year levelized costs over the life of the project. To represent these varying revenue requirements for fixed and variable costs, a "tenth year levelized" value was computed using the "present worth" concept of money based on the assumptions shown in the Estimate Basis/Financial Criteria for Revenue Requirement Calculations table included in Appendix B.

By combining costs, carrying charges, and levelizing factors, a tenth year levelized busbar COE for the 85 percent capacity factor was calculated along with the levelized constituent values. The algorithm for this cost calculation is:

$$\text{Power Cost (COE)} = \frac{(\text{LCC}+\text{LFOM}) \times 100\ /\$}{\text{CF}/100 \times 8760\ \text{h/y}} + \text{LVOM} + \text{LCM} - \text{LB} + \text{LFC}$$

where:

LCC	=	Levelized carrying charge, $/kW-y
LFOM	=	Levelized fixed O&M, $/kW-y
LVOM	=	Levelized variable O&M, cents/kWh
LCM	=	Levelized consumable, cents/kWh
LB	=	Levelized byproducts (if any), cents/kWh

LFC	=	Levelized fueled costs, cents/kWh
CF	=	Plant capacity factor, %

The principal cost and economics output for this study, the Capital Investment and Revenue Requirement Summary, is included in Appendix B for each technology. These summaries present key TPC values and other significant capital costs, reference year operating costs, maintenance costs, consumables, fuel cost and a first year and tenth year levelized production cost summary as well as the tenth year levelized busbar COE.

4.2 ECONOMIC/FINANCIAL RESULTS

4.2.1 Capital Cost Results

A summary comparison of the TPC was introduced previously on Tables 4-3a and 4-3b. These tables show the account total and $/kW for each of the CCT cases, and include reference results for a new pulverized coal plant and NGCC plant.

In addition to the table, the capital cost in $/kW, at the TPC level, of each technology is illustrated in Figure 4-2. These costs are grouped by major plant systems: coal, sorbent, and ash handling; feedwater and plant miscellaneous systems; technology, consisting of the gasification and gas cleanup or the boiler; combustion turbine, HRSG, and exhaust duct and stack; steam turbine generator and cooling water system; electrical and I&C; and site, structures, and foundations.

4.2.2 Economic Results

A summary comparison of selected cost and financial data is shown on Tables 4-5a and 4-5b. In addition to the total TPC, these tables show first year and tenth year levelized costs for all operating, maintenance, fuel, and emissions, as well as tenth year levelized COE. The details for each case are in Appendix B.

4.2.3 Tax Incentives

One approach to assisting the CCT plants to be competitive with conventional plants during the period between first demonstration and mature commercial operation would be through tax incentives. In a paper prepared by D. South, et al.[37] for the DOE, five possible tax incentives were identified and evaluated, individually and in combinations, compared to no incentive. These incentives are listed below:

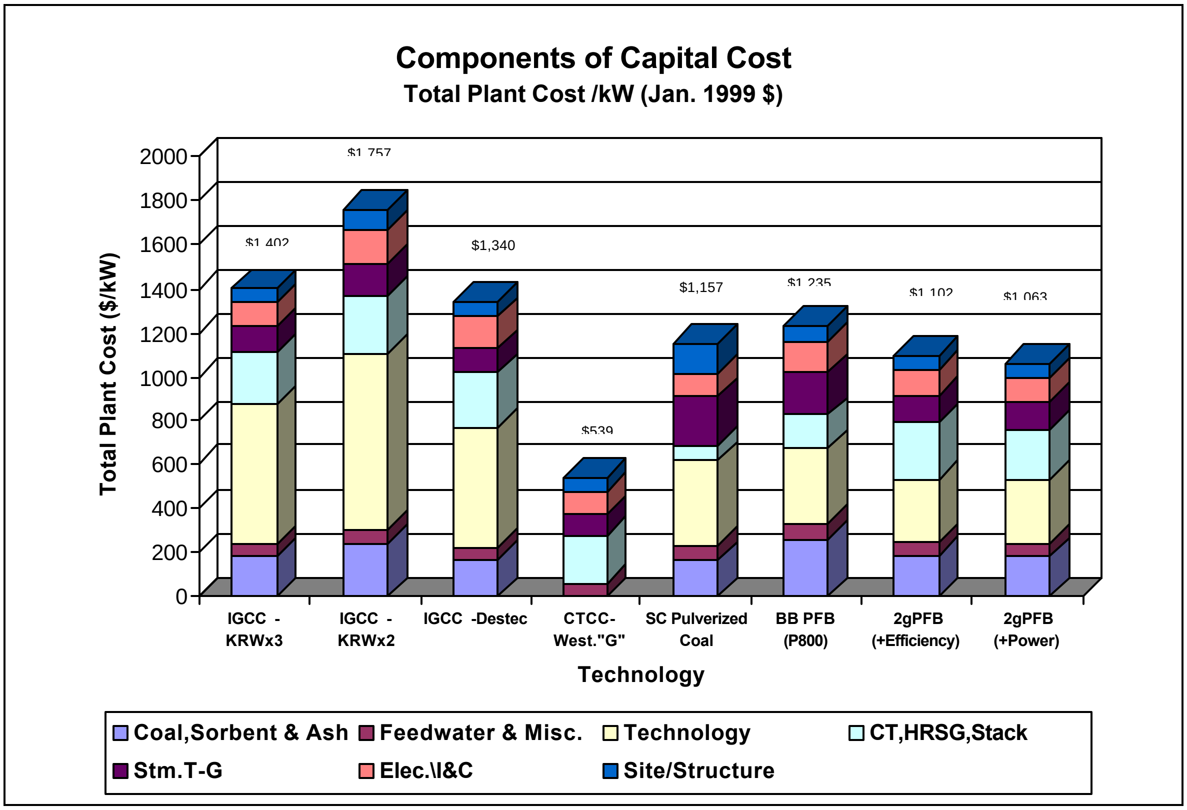


Figure 4-2
Components of Capital Cost

- Shortened Depreciable Life (5 year or 10 year)
- Remaining Undepreciated Basis on Existing Plant Tax Deductible for Repowering Project
- Investment Tax Credit (10 percent)
- Section 29 Tax Credit
- Production Tax Credit

The results of the referenced evaluation suggest that without incentives, competitiveness of CCT plants will not occur until at least 2010 to 2015. With incentives, the CCT plants could be competitive today. Permitting incentives, though minor in cost impact, still offer additional support to achieve a competitive position. These various incentives would apply only to the first several units of a technology, until the technology achieves mature commercial status.

4.2.4 <u>Pre-Production (Staged Operation) Revenue</u>

One approach to reducing the impact of the capital cost on the economics of the CCT projects would be to commercialize a portion of the plant prior to completion of the entire facility. This step would allow for revenue to be generated prior to completion and startup of the entire facility. This could be accomplished

Table 4-5a
Case Comparisons - Selected Cost & Financial Data

CASE:	IGCC - KRW x 3		IGCC - KRW x 2		IGCC - Destec		NGCC "G"		Supercritical PC	
	Base Year $		Base Year $		Base Year $		Base Year $		Base Year $	
Base (Reference Year Jan. 1999)										
MWe (net)	384.9		198.1		348.2		323.4		404.1	
Net Plant Heat Rate-Average Annual	7,247		8,086		7,526		6,827		8,520	
TOTAL PLANT COST (TPC)-$x1000	$539,525		$348,123		$466,594		$174,386		$467,524	
TPC $/kW	1,401.7		1,757.4		1,339.9		539.2		1,157.1	
TOTAL CAPITAL REQUIREMENT (TCR) - $x1000	$614,726		$389,548		$512,442		$187,082		$528,211	
TCR $/kW	1,597.1		1,966.6		1,471.6		578.5		1,307.3	
OPERATION & MAINTENANCE COSTS - 4/kWh	Reference	Levelized	Reference	Levelized	Reference	Levelized	Reference	Levelized	Reference	Levelized
Fixed O & M	0.44	0.44	0.61	0.61	0.45	0.45	0.16	0.16	0.30	0.30
Variable O & M	0.08	0.08	0.11	0.11	0.08	0.08	0.03	0.03	0.05	0.05
Consumables	0.28	0.28	0.31	0.31	0.12	0.12	0.03	0.03	0.21	0.21
Byproduct Credit & Emission Credits/ Costs										
Fuel	0.92	0.79	1.03	0.89	0.96	0.82	1.88	2.07	1.08	0.93
TOTAL PRODUCTION COST	1.72	1.59	2.06	1.92	1.61	1.48	2.10	2.29	1.65	1.50
LEVELIZED CARRYING CHARGES (Capital)		3.24		3.99		2.98		1.17		2.65
LEVELIZED BUSBAR COST OF POWER - 4/kWh Levelized (10th Year $)		**4.83**		**5.90**		**4.46**		**3.47**		**4.15**

NOTES:

TPC costs in Jan.1999 $
TCR costs include escalation for 2005 initial operation
1st year O&M (Production) Costs in 2005 dollars
Levelized = 10th year O&M & COE for years 2005 to 2025 operation
Credits excluded from baseline analysis, refer to Sensitivity Analysis, Sec.4.3
Production costs & COE determined at constant 85% capacity factor

Fuel Cost Basis:	Coal	Nat.Gas
Coal = Illinois #6 @ 11,666 Btu/lb		
Jan.1999 base price, $/$10^6$ Btu	1.27	2.758
Annual Fuel escalation, real (1999-2005)	-1.34%	1.07%
Annual Fuel escalation, real (2005-2025)	-1.35%	0.65%
General Annual escalation	0.00%	0.00%

Fuel Price based on analysis of EIA 1999 data (Ref. Table A-3)
Fuel escalation based on analysis of EIA 1999 data (Ref. Table A-3)

Table 4-5b
Case Comparisons - Selected Cost & Financial Data

CASE:	BB PFB (P800)		2gPFB(+Efficiency)		2gPFB (+Power)		NGCC "G"		Supercritical PC	
	Base Year $		Base Year $		Base Year $		Base Year $		Base Year $	
Base (Reference Year Jan. 1999)										
MWe (net)	424.6		379.0		431.3		323.4		404.1	
Net Plant Heat Rate-Average Annual	8,354		7,273		7,463		6,827		8,520	
TOTAL PLANT COST (TPC) - $x1000	$524,396		$417,545		$458,419		$174,386		$467,524	
TPC $/kW	1,235.0		1,101.7		1,062.9		539.2		1,157.1	
TOTAL CAPITAL REQUIREMENT (TCR) - $x1000	$576,978		$459,441		$504,556		$187,082		$528,211	
TCR $/kW	1,358.8		1,212.3		1,169.9		578.5		1,307.3	
OPERATION & MAINTENANCE COSTS - 4/kWh	Reference	Levelized	Reference	Levelized	Reference	Levelized	Reference	Levelized	Reference	Levelized
Fixed O & M	0.34	0.34	0.37	0.37	0.34	0.34	0.16	0.16	0.30	0.30
Variable O & M	0.06	0.06	0.07	0.07	0.06	0.06	0.03	0.03	0.05	0.05
Consumables	0.28	0.28	0.21	0.21	0.21	0.21	0.03	0.03	0.21	0.21
Byproduct Credit & Emission Credits/ Costs										
Fuel	1.06	0.91	0.92	0.80	0.95	0.82	1.88	2.07	1.08	0.93
TOTAL PRODUCTION COST	1.74	1.60	1.57	1.44	1.56	1.43	2.10	2.29	1.65	1.50
LEVELIZED CARRYING CHARGES (Capital)		2.76		2.46		2.37		1.17		2.65
LEVELIZED BUSBAR COST OF POWER - 4/kWh Levelized (10th Year $)		**4.35**		**3.90**		**3.80**		**3.47**		**4.15**

NOTES:

TPC costs in Jan.1999 $
TCR costs include escalation for 2005 initial operation
1st year O&M (Production) Costs in 2005 dollars
Levelized = 10th year O&M & COE for years 2005 to 2025 operation
Credits excluded from baseline analysis, refer to Sensitivity Analysis, Sec.4.3
Production costs & COE determined at constant 85% capacity factor

Fuel Cost Basis:	Coal	Nat.Gas
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Jan.1999 base price, $/$10^6$ Btu	1.27	2.758
Annual Fuel escalation, real (1999-2005)	-1.34%	1.07%
Annual Fuel escalation, real (2005-2025)	-1.35%	0.65%
General Annual escalation	0.00%	0.00%

Fuel Price based on analysis of EIA 1999 data (Ref. Table A-3)
Fuel escalation based on analysis of EIA 1999 data (Ref. Table A-3)

by operating the combustion turbine portion of the plant on natural gas. The possibility may exist to operate the combined cycle plant on natural gas if the construction schedule is structured to allow either or both of these plant sections to operate prior to the inservice date of the total plant. The advantages for this approach include the following: portions of the plant placed in service early would cease to accumulate AFDC and revenue from generation could offset a portion of the fixed charges, carrying charges, component of the annual expenses in the early years of the project. If this approach is adopted, there are other considerations that could increase costs, but their impact relative to the revenue generated should be minor. For example, additional work would be required to obtain permits for operation of the plant with natural gas, and, depending on the characteristics of the specific site, a gas pipeline may be required in order to furnish the volume of gas required to operate at full capacity.

4.2.5 Financing Options

Project financing is moving away from the traditional utility finance approach. With independent power producers, project financing is occurring on the basis of a large fraction of debt and equity participation in the range of 20 to 30 percent. In addition, the changing utility environment has resulted in new options for financing projects, and opened up opportunities for industrial customers seeking an alternative to internal funding of their energy projects. Some utilities have created unregulated subsidiaries that invest in their customers' energy facilities. Capital assistance may be provided by the utility under one of the following service arrangements:

- The utility serves as lessor of energy projects/equipment, with a finance partner. Under this arrangement, the utility may offer:
  - Finance leases (capital lease),
  - Operating leases (off-balance sheet), or
  - True leases.
- The utility acts as lease broker — the utility shops potential deals around to a variety of sources.
- The utility uses a "phone book" approach — each finance opportunity is treated by the utility as a bid, and is submitted to a number of fund sources for consideration.

There are favorable and unfavorable features to each of these arrangements. For example, having the utility act as the lessor in partnership with a national finance firm may result in excellent service and competitive rates for the lessee. The downside of this approach is that only the most attractive deals will be financed and viable, and high-risk projects will be rejected.

Having the utility function as a lease broker may result in a higher project approval rate, but service will not be as responsive as in the finance partner arrangement, and will generally result in higher rates to the lessee.

The least attractive arrangement is the phone book approach, since there is no commitment on the part of the utility under this arrangement, and the potential finance organizations may not only be unresponsive, but may also offer high rates.

The availability of these types of financing options will be highly dependent on the size and type of project and the identity of the customer.

4.3 SENSITIVITY ANALYSIS

In Section 3.2 elements of risk were identified. Any "risk allowances" added to the capital cost estimate would provide costs associated with plant components that have not yet been fully demonstrated. Each of the systems and defined risk elements listed in Section 3.2 are critical to achieving the performance and cost goals of an advanced technology plant. Even allowing for success of the CCT demonstration projects, there will still be performance and cost uncertainties that may impact a project's economics. Table 4-6 lists an example of problems that may lower performance or increase cost in IGCC plant operation and the likely solution.

Table 4-6
Problem/Solution: IGCC Plant Operation

Problem	Solution	Cost Impact
Decrease in Coal Throughput	Higher Gasifier Capacity	Higher Capital Cost
Increased Sorbent Throughput	Higher Gasifier Capacity	Higher Capital Cost Higher O&M
Lower Sorbent Reactivity	Higher External H_2S	Higher Capital and O&M for External H_2S
Reduced Carbon Conversion	Increase Coal	Higher Fuel Costs
Increased Air Consumption to	Lower Btu Gas	Higher Fuel Costs
Internal Corrosion/Erosion	Extended Maintenance	Higher O&M Costs

To provide the decision-maker with an approach to evaluate potential risks, sensitivity analyses for operational parameters have been developed including capacity factor, heat rate, capital cost, production cost, fuel escalation, and byproduct credit.

4.3.1 Capacity Factor

Capacity factor of any power plant is driven by a number of parameters impacting plant availability. These include scheduled and unscheduled downtime for maintenance, and duty cycle based on economic or environmental dispatching. Typical capacity factors for conventional fossil-fueled power plants range from 35 to 85 percent. It is expected that CCT plants will have high capacity factors due to low production costs and reduced emissions compared to current base load plants. However, demonstration of the technology's availability and production cost is required prior to realizing expected capacity factors.

Studies by Resource Data Institute on U.S. utilities indicate capacity factors of 76 percent to 80 percent for coal-fired power plants, based on historical operation of top performing units in 1993. Historical data for natural gas combined cycles indicate only a few units operated at a capacity factor of 65 percent or greater in 1994.

Evaluating all operating NGCC units in 1994 shows an average capacity factor of 38 percent. However, with the new generation of high-efficiency combustion turbines, the NGCC unit capacity factor can be expected to increase.

Figure 4-3 presents the sensitivity on COE from changes in capacity factor, from 45 to 85 percent, for the competing plant designs. As indicated, capacity factor has a significant impact on COE over the range considered typical for these units to be operating. The coal-based technologies, over the range of 65 to 85 percent, have a COE variation of 20 to 25 percent. The NGCC over the same range has a COE variation of less than 15 percent. This COE difference compared to the coal-based technologies is largely due to the influence of capital investment since that fixed annual cost is apportioned over fewer kilowatt hours of operation. In addition, in Figure 4-3, it is evident that if one technology realizes a capacity factor that is greater or less than the other candidate technology, the relationship of COE values can change significantly.

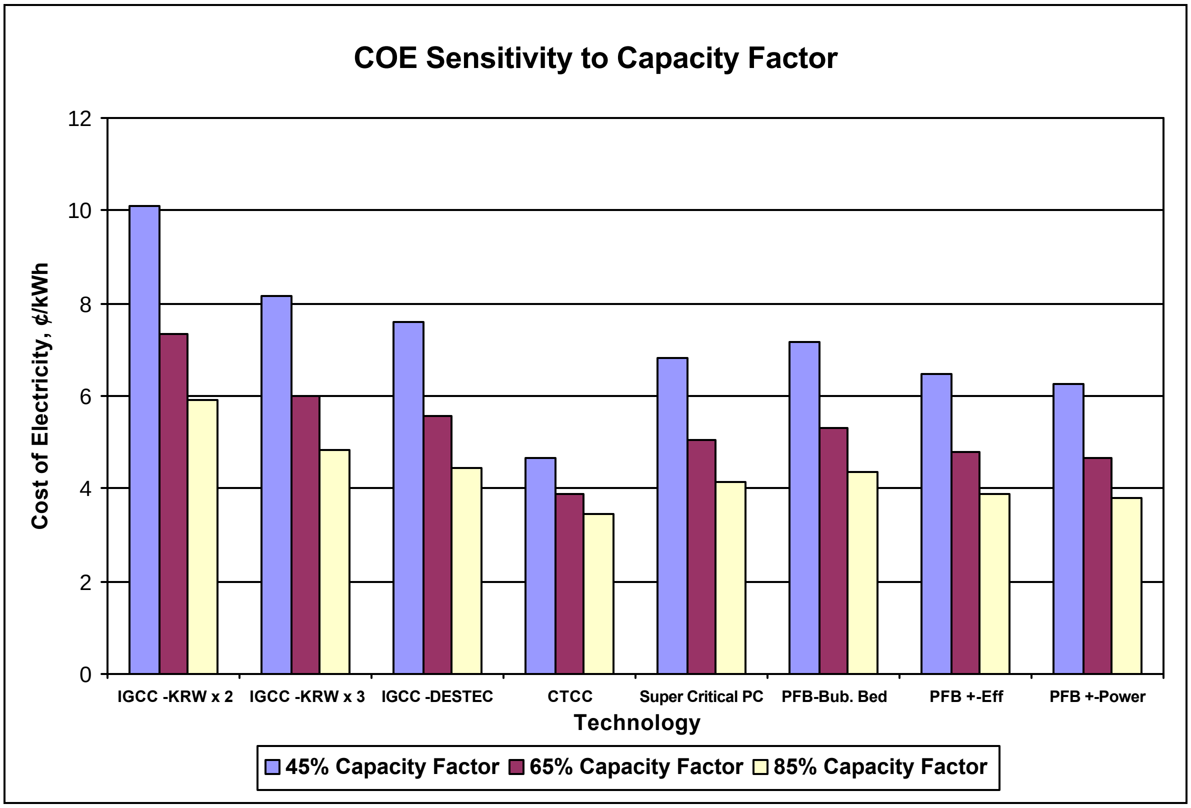

Figure 4-3
Cost of Electricity Sensitivity to Capacity Factor

4.3.2 Heat Rate

Change in net plant heat rate can be caused by numerous parameters in the process stream. Any additional usage of energy within the system can be generally interpreted as a decrease in thermal plant efficiency, and results in a rise in heat rate. The heat rate assigned to a new technology is based on a heat and material balance that results from operational assumptions such as thermal conversion into usable energy, thermal losses, process control, part load operation, and projected auxiliary loads throughout the plant. Changes in duty cycle due to dispatch requirements will drop process efficiency, affecting the heat rate. The economics of each of the power plants under consideration are based on a normal heat rate evaluation, which resulted from assumed performance parameters. Conventional performance analyses use heat rates based on maximum efficiency. The range of heat rates for sensitivity analysis is treated as a percentage of the normal or maximum (full load) on which the plant designs are based and are shown in Table 4-7. Figure 4-4 presents the sensitivity on COE from changes in heat rate, and indicates a minimal difference across the range of heat rate considered. For all of the technologies, this range of heat rates has only a slight effect on the COE. This result is markedly different from the effect shown in Figure 4-3 for capacity factor changes.

Table 4-7
Range of Heat Rates

	IGCC	PC	GTCC
Design Heat Rate, percent	100	100	100
Maximum Heat Rate, percent	100	100	100
Minimum Heat Rate, percent	75	80	90

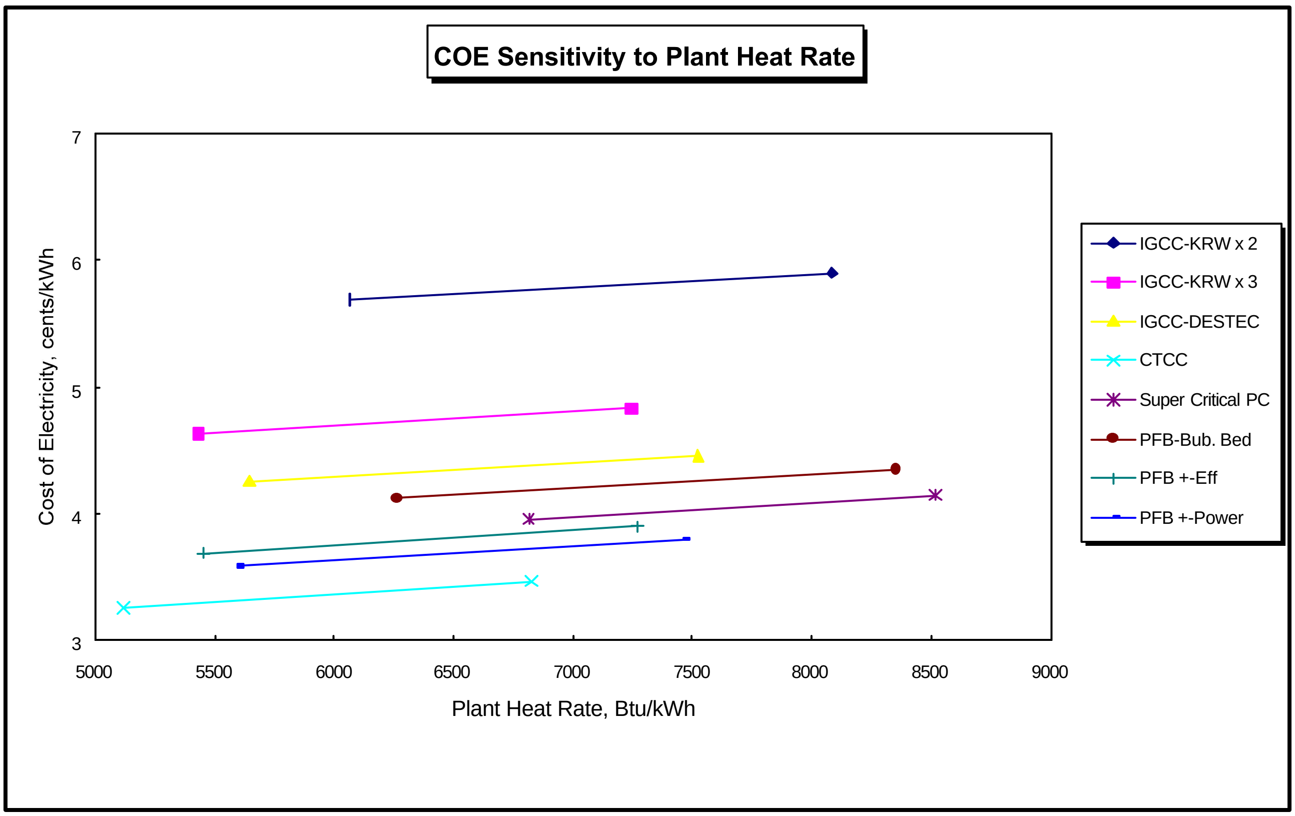

Figure 4-4
Cost of Electricity Sensitivity to Plant Heat Rate

The effects of capital cost and production cost are examined in subsequent subsections. These results suggest that comparable changes in capital cost or production cost have a greater influence on overall COE. However, more specific correlation of these variables would be necessary to establish precise relationships.

4.3.3 Capital Cost

The capital cost for advanced technologies can vary due to the site-specific impacts on a plant, additional systems not previously recognized, and additional cost to correct for lower performance. The increased cost to achieve expected performance was addressed through the use of process contingency, refer to Section 4.1.2.2, and further examined through the use of risk analysis on those components considered to be at highest risk.

In addition to subjective discussions as to the evaluation of process contingency (presented in Section 3.2), a Range Estimating Program (REP) was used to provide a more objective analysis of the risk associated with those components considered to be developmental. Risk analysis was performed for two of the IGCC cases. If the analysis were also applied to PFBC technology, results similar to the Destec case would be expected. While this approach was applied only to capital costs, a similar analysis could be applied to operating costs. Appendix C provides a brief overview of the REP program and methodology.

Discrete cost elements representing areas of developmental risk were identified for each of the two cases to be analyzed. Target values for each of these elements were established as the sum of the bare construction cost plus process contingency. Each element was then evaluated to establish a relative confidence, or probability of meeting or underrunning the target cost, and its extreme limits of risk and opportunity based on a 1 in 100 occurrence. The selection of developmental risk items and the establishment of values for probabilities and risk/opportunity limits to be utilized in the analyses were achieved through an open discussion forum and represents the consensus opinion of the estimating and design team. Issues considered in the value selection process were discussed in Section 3.2.

Data inputs for each case were combined in a statistical model, and risk analysis performed using a Monte Carlo simulation (1,000 simulations). Model results are presented as a table of probabilities and corresponding contingency values required to achieve the desired probability of success or confidence level. The resulting total estimate values for the selected developmental risk elements and the associated confidence levels are presented in graphical form in Figures 4-5 and 4-6. Data input summaries and model results that support these figures are included in Appendix C.

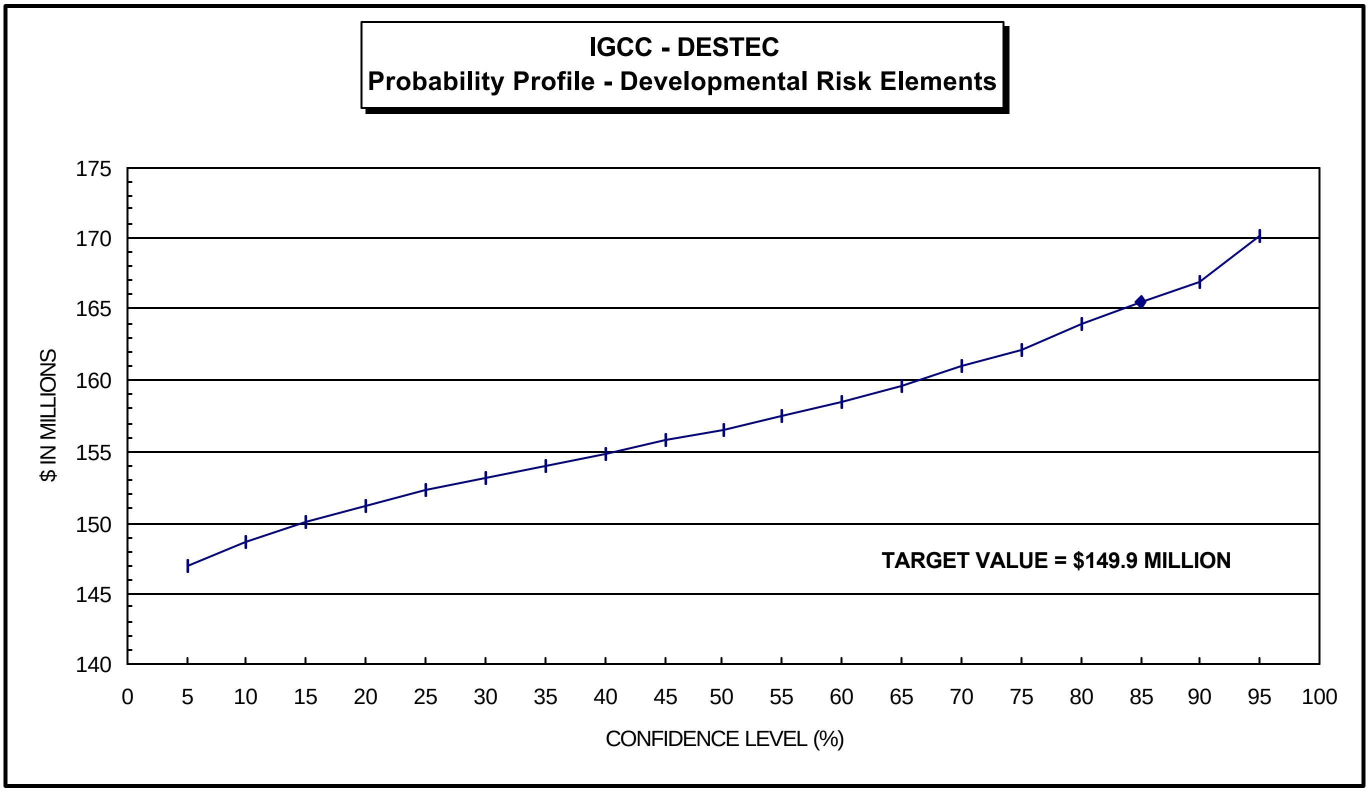

Figure 4-5
Total Estimated Value and Associated Confidence Levels - Destec Analysis

Developmental risk elements considered in the Destec analysis include gasifier and auxiliaries, high-temperature cooling, gas desulfurization, sulfur recovery, chloride guard, particulate removal, and combustion turbine generator. The resulting target value for this case is $149.9 million. The results of the risk analysis indicate a 15 percent probability that the actual cost will fall at or below the target value. To achieve a 75 percent confidence level would require that a process contingency of 8.2 percent be added to the cost of the developmental risk components.

Developmental risk elements considered in the KRW analysis include gasifier and auxiliaries, high-temperature cooling, recycle gas system, booster air compression, gas desulfurization, sulfur recovery, chloride guard, particulate removal, and combustion turbine generator. The resulting target value for this case is $223.8 million. The results of the risk analysis indicate a 60 percent probability that the actual cost will

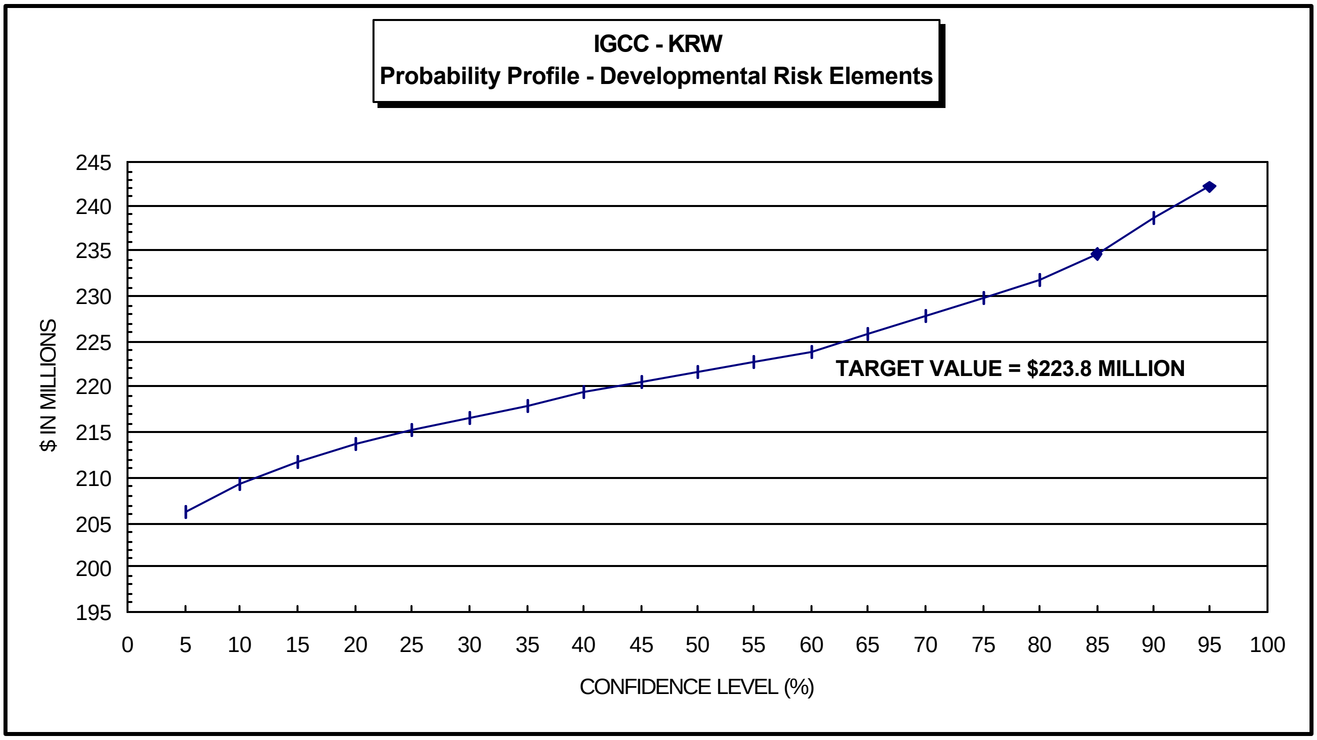

Figure 4-6
Total Estimated Value and Associated Confidence Levels - KRW Analysis

fall at or below the target value. This confidence level is four times higher than that established for the Destec case. To achieve a 75 percent confidence level would require that a process contingency of 2.7 percent be added.

In both cases, Destec and KRW, the added contingency for the developmental components, 8.2 percent and 2.7 percent, respectively, at the 75 percent confidence level has a minor effect at the total capital requirement (TCR) level. The impact at the TCR level for Destec is an increase of 2.4 percent and for KRW the increase is 0.1 percent.

4.3.4 Production Cost

Similar to the capital cost, there are many factors that can contribute to a change in the production cost. This section does not attempt to determine the specific causes for the changes and associated cost impacts with each, but rather examines the net cumulative effect of changes to production cost.

Some of the general factors that could impact the production cost include labor wage rates, number of operators, maintenance cost, unit cost of the consumable, quantities for the consumable (i.e., more sorbent required due to lower effectiveness), lack of a market for the byproduct or emission credits, change in the net plant heat rate or output that alters the unit fuel consumption, or a change in the unit cost of the fuel. For this sensitivity, the range of production cost was varied between -20 percent and +25 percent for all technologies. The results of this analysis are shown in Figure 4-7.

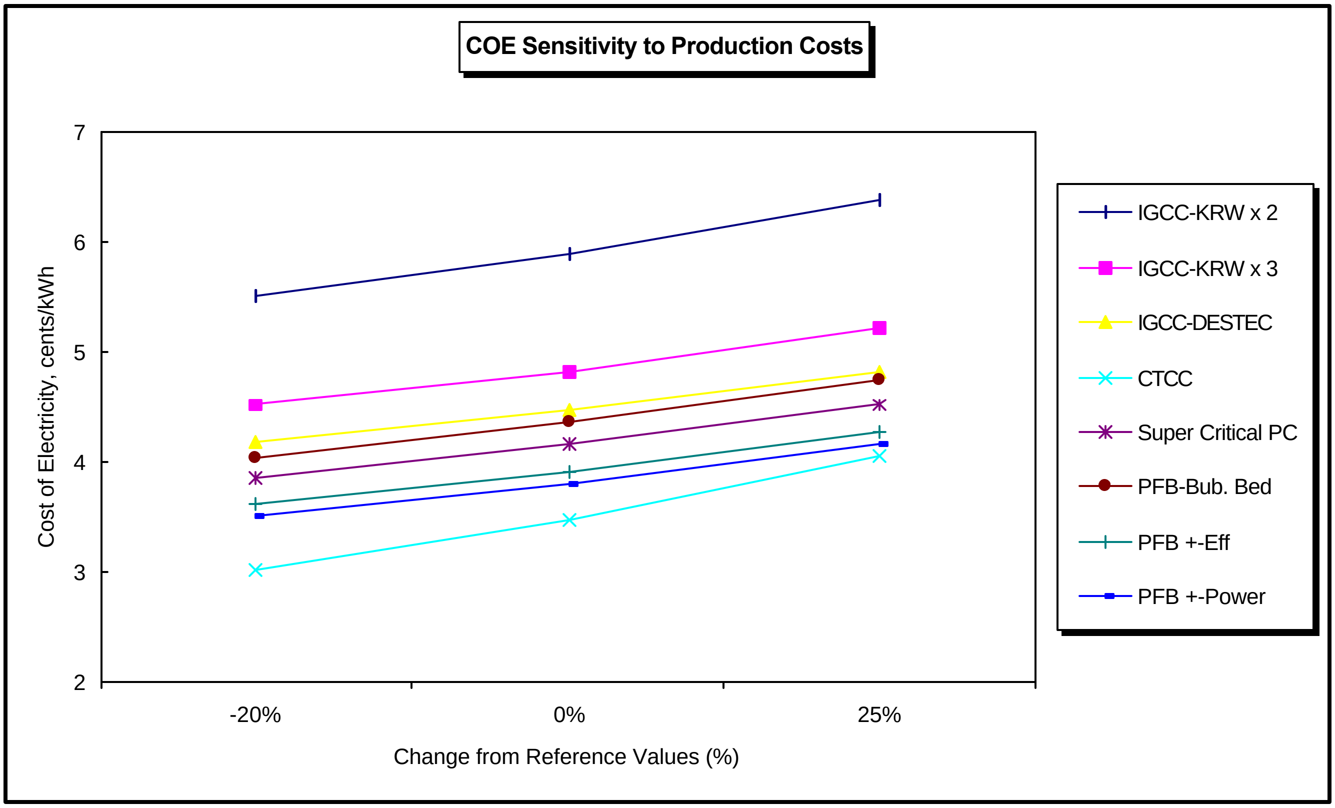

Figure 4-7
Cost of Electricity Sensitivity to Production Costs

4.3.5 Fuel Escalation Rate

The future escalation of fuel costs is in constant change as evident from comparing the Energy Information Agency 1995 Annual Energy Outlook (AEO) and the equivalent reports up to the current 1999 report. In order to recognize the impact of these escalation rates and at the same time investigate the competitiveness of the gasification combined cycle plant to conventional technology, a sensitivity analysis was performed on the basis of the reference, and high growth fuel real escalation annual rates presented in the 1999 AEO.[1] The results of this analysis are presented in Figure 4-8 and Figure 4-9.

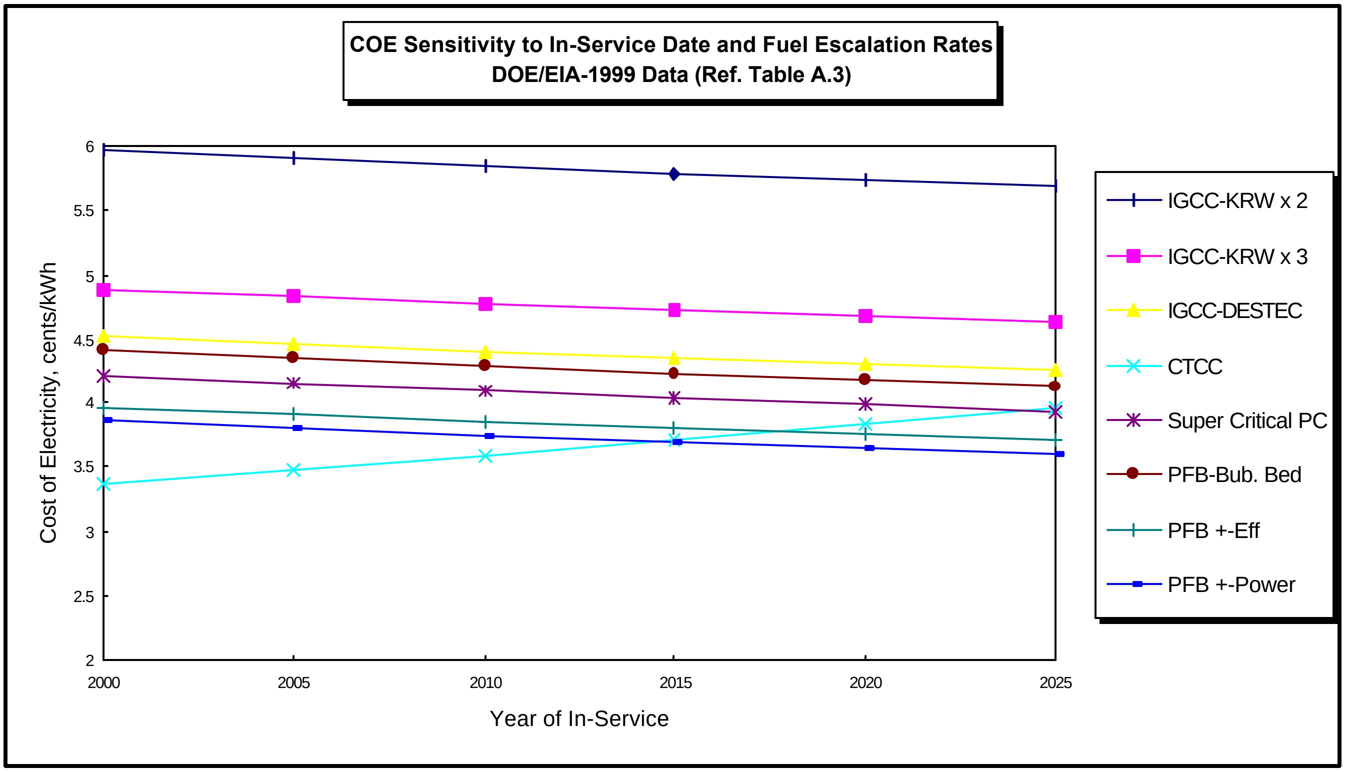

Figure 4-8
Cost of Electricity Sensitivity for Reference Economic Growth

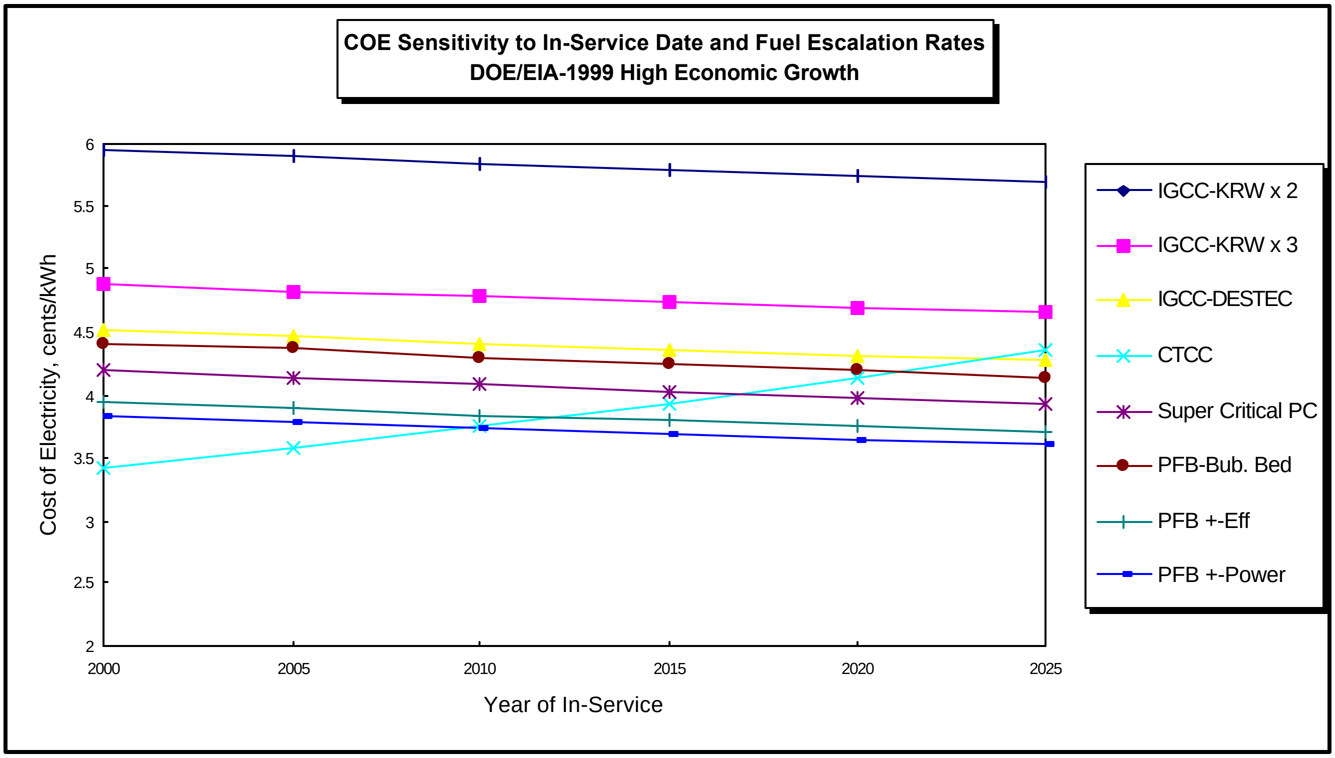

Figure 4-9
Cost of Electricity Sensitivity for High Economic Growth

Figure 4-9 shows results for the two KRW IGCC cases, Destec IGCC, the three PFBC cases, CTCC and supercritical PC plants. As indicated, on the basis of fuel cost (escalation) alone, IGCC is competitive with NGCC at future decision periods. However, it must be recognized that fuel cost is only one component of the decision process in technology selection.

4.3.6 Byproduct Credits

Process byproducts, such as gypsum and sulfuric acid, or emissions credits, are economic incentives that may play a vital role in assuring the financial success of advanced technology power generation projects. It is important for the decision-maker to understand the impact such products may have on the overall project economics, and just as important to understand the market, which establishes the product price. These credits fall into two categories, byproduct and emissions. Byproduct recognition is limited to gypsum for the PC plant and sulfuric acid for the Destec IGCC plant, and emission credits are limited to sulfur dioxide and NOx. For a cost basis for the sulfuric acid credit, refer to Section 3.1.1 for an assessment of the likely price for sulfuric acid. The gypsum was not assigned a credit value since this commodity is heavily dependent on geographic region and customer requirements. As a result of this assumption, credits for the PC plant could vary slightly depending on the specifics of the market. Due to this variability in prices for byproducts, the site and local market impacts, and the inability of new plants to recognize emission credits (repowering projects could likely qualify for emission credits), structured sensitivities for credits were not performed.

4.4 COMPARISON MODEL

This study uses certain characteristics, assumptions, and parameters that are common to all of the power plant configurations. A simplified comparison model was developed to allow the user to evaluate the effects of changes to these characteristics, assumptions, and parameters using the Microsoft® Excel spreadsheet format. The model allows the user to change process and economic variables and see the effects and impact of the change on each individual power plant. The model will allow the user to change the following parameters:

- Process:
  - Coal flow
  - Coal Btu content
  - Limestone characteristics
  - Limestone stoichiometric ratio
  - Particulate, NOx, and SO_2 removal efficiencies
  - Capacity factors used to calculate the yearly productions of air pollutants

- Economic:
  - Delivered cost of fuel
  - Capital structure
  - Fuel escalation
  - Levelized carrying charge

The model is intended to provide the user with the ability to make small changes to the process. The changes to the process are based on linear relationships between the default settings and the new settings. This will give the user an estimated impact of the change that was made. Table 4-8 summarizes the changes that are allowed and the impact that will occur.

The model contains input sheets that are navigated to by clicking on the appropriate icons. Once you have arrived at an input sheet you may change the appropriate parameters and see the results of the changes to the right of the parameter changed.

Table 4-8
Comparison Model Summary

Change	Impact	Universal or Specific
Coal Flow	Power Output Auxiliary Power Consumption Limestone Flow Heat Rate Efficiency Emissions (tons/year)	Specific
Coal HHV	Coal Flow Gas Flow Steam Flow Power Output Auxiliary Power Consumption Limestone Flow Heat Rate Efficiency Emissions (lb/10^6 Btu and tons/year)	Universal
Auxiliary Power	Heat Rate Efficiency Emissions (lb/10^6 Btu) Power Output Heat Rate	Specific
Limestone Type	Limestone Flow Power Consumption Power Output Heat Rate	Universal
Limestone Stoichiometric Ratio	Limestone Flow Power Consumption Power Output Heat Rate	Specific
Particulate Removal Efficiency	Outlet Particulate Loading Power Consumption Power Output Heat Rate	Specific

Change	**Impact**	**Universal or Specific**
NOx Removal Efficiency	Outlet NOx Loading	Specific
SO_2 Removal Efficiency	Outlet Particulate Loading Power Consumption Limestone Usage Power Output Heat Rate	Specific
Capacity Factors	Yearly Particulate Loading	Specific

5.0 TECHNOLOGY COMPARISONS

A summary review of the advanced and conventional power systems is presented based on the conceptual designs and cost estimates defined in Sections 7.0 through 10.0 in Volume II, providing the decision-maker with comparative estimates of plant performance, economics, and environmental performance. A total of eight power plants covering three technology concepts have been described to date including integrated gasification combined cycle, pressurized fluidized-bed combustion, natural gas combined cycle, and pulverized coal.

5.1 PERFORMANCE

The performance summary of the eight power plant concepts is provided in Table 5-1 and Figures 5-1 and 5-2. Values for the IGCC were developed from information based on the KRW air-blown gasification process and the Destec oxygen-blown coal gasification process. These designs represent two of the three gasifier concepts in the DOE Clean Coal Technology demonstration program, the other being the Texaco oxygen-blown entrained-bed gasification process. Presently all three projects are either in or nearing the operational phase of demonstration. Values for the PFBC were developed from information obtained from demonstration programs being conducted by DOE. Plant capacities were defined to fit potential utility additions for baseload dispatching in the year 2005, that is, 200 to 400 MW. Therefore, performance analysis for the IGCC, PC, PFBC, and gas turbine plants are representative of plants in a baseload operation mode. The configurations utilize the gasifiers, gas turbines, and gas cleanup concepts that are expected to be commercially offered by 2002, the latest date for a decision to proceed in order to meet the 2005 in-service date. Performance values are based on the use of Illinois No. 6 coal.

Table 5-1
Comparison of Performance Summaries

Power Plant	KRW 400 MW	KRW 200 MW	Destec 400 MW	PFBCC high output	PFBCC high efficiency	BBFBC	NGCC	PC 400 MW
Gas Turbine (gross MW)	232.2	116.9	262.6	209.5	206.7	79.5	223.2	NA
Steam Turbine (gross MW)	170.7	92.7	139.4	246.9	195.0	373.8	107.7	427.1
Auxiliary Loads, MW	18.0	11.5	53.8	25.1	22.8	28.6	7.5	23.0
Net Power, MW	384.9	198.1	348.2	431.3	378.9	424.7	323.4	404.1
Heat Rate, Btu/kWh HHV	7,247	8,086	7,526	7,463	7,273	8,352	6,827	8,520
Efficiency, % HHV	47.1	42.2	45.4	45.8	47.0	40.9	50.0	40.1
Heat Rate, Btu/kWh LHV	7,175	8,006	7,451	7,389	7,200	8,268	6,148	8,435
Efficiency, % LHV	47.6	42.7	45.8	46.2	47.4	41.3	55.6	40.5

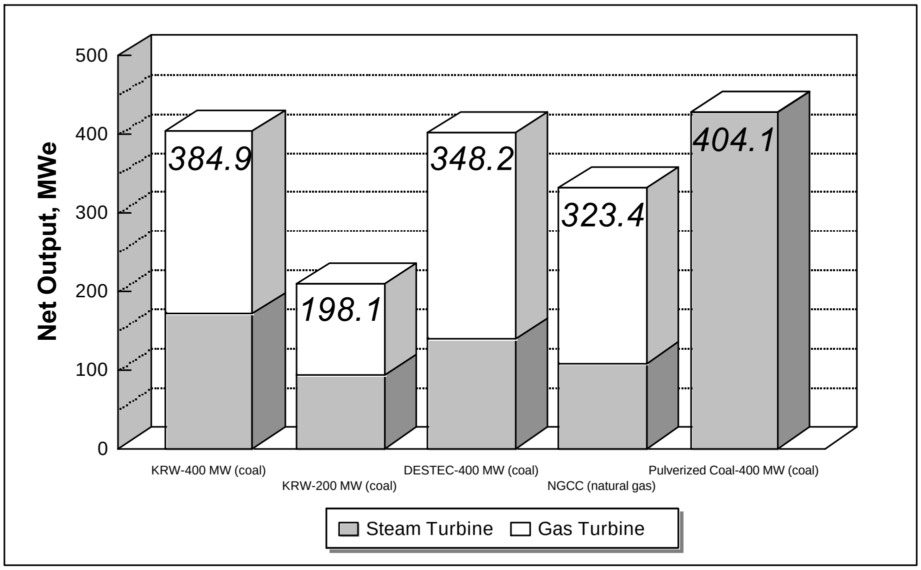

Figure 5-1a
Comparison of Plant Net Output

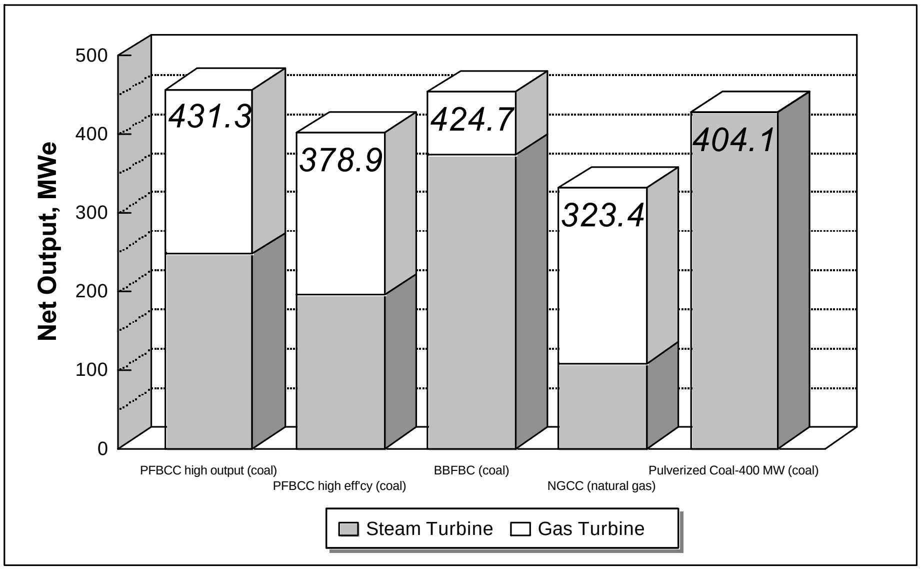

Figure 5-1b
Comparison of Plant Net Output

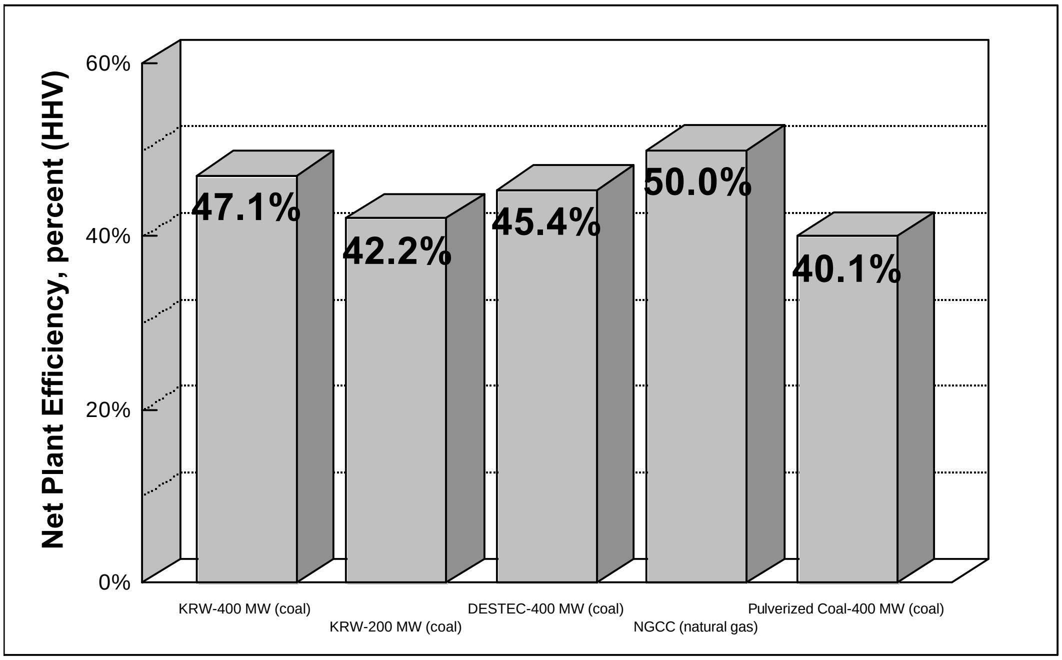

Figure 5-2a
Net Plant (HHV) Efficiency Comparison

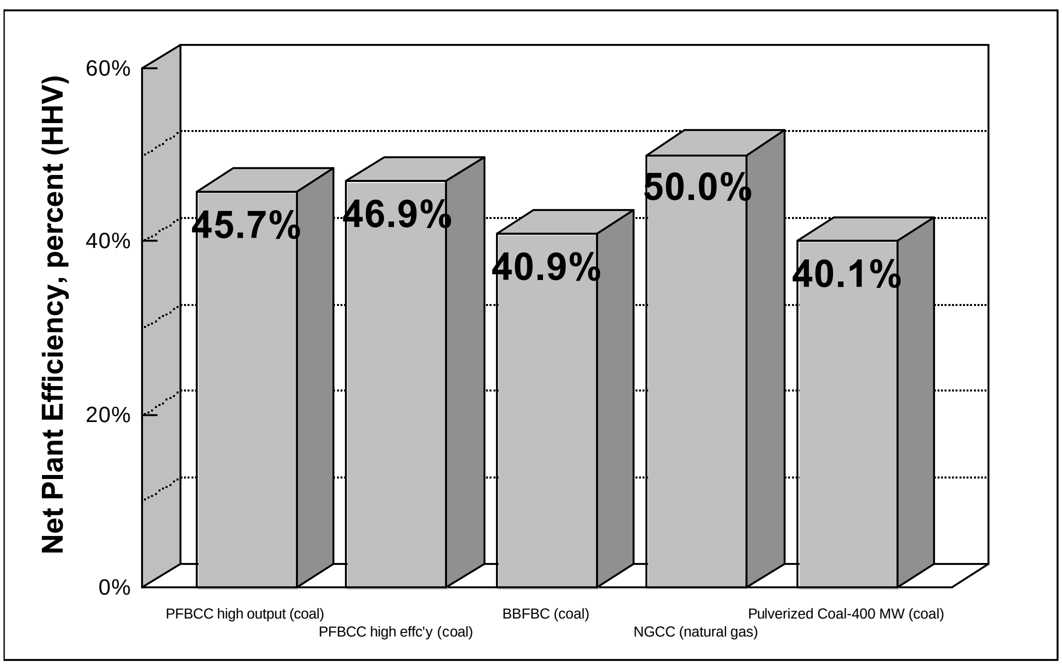

Figure 5-2b
Net Plant (HHV) Efficiency Comparison

The KRW 400 MW IGCC plant is based on the KRW air-blown coal gasification process supplying low-Btu gas to a Westinghouse 501G gas turbine/combined cycle power generating plant. This particular machine provides values of power output, airflow, and compressor pressure ratio that, coupled with an appropriate steam cycle, produce a nominal 400 MW net output. The IGCC portion of the plant is configured with three gasifier islands, each including in-situ desulfurization and a hot gas polisher. Steam conditions at the turbine admission valves are set at 1800 psig/1000 EF (HP), 395 psig/1000 EF (IP), and 65 psig/592 EF (LP). The resulting plant produces a net output of 385 MW at a net efficiency of 47.1 percent on an HHV basis.

The 200 MW KRW IGCC plant is based on selection of a gas turbine derived from the Westinghouse 501D5A machine and produces a nominal 200 MW net output. The IGCC portion of the plant is configured with two gasifier islands, each including in-situ desulfurization with a hot gas polisher. The resulting plant produces a net output of 198 MW at a net efficiency of 42.2 percent on an HHV basis.

Destec's oxygen-blown coal gasification process supplies medium-Btu gas to a gas turbine/combined cycle derived from the Westinghouse 501G machine to produce a nominal 350 MW net output. The IGCC portion of the plant is configured with one gasifier island, which includes a moving-bed, hot gas desulfurizer. The resulting plant produces a net output of 348 MW at a net efficiency of 45.3 percent on an HHV basis.

The CPFBC utilizes compressed air supplied to a fluidized combustor/boiler, and the coal is burned under pressure. The flue gas passes through a gas turbine. High-pressure steam is generated in tubes positioned in the boiler that is fed to a steam turbine. Two cases are presented: the high-output plant, which generates a net 431.3 MWe at a net efficiency of 45.8 percent (HHV), and a high-efficiency plant, which generates a net 379 MW at a net efficiency of 47.0 percent (HHV).

The BBFBC is based on the ABB carbon design and also uses compressed air, but the air is supplied to a bubbling bed combustor/boiler. The coal is burned under pressure. The flue gas passes through a gas turbine, and steam generated in the boiler is used to supply a steam turbine. The plant produces a net output of 424.6 MW at a net efficiency of 40.9 percent (HHV).

A natural gas-fired combustion turbine based on the Westinghouse 501G machine coupled with a heat recovery steam generator to generate steam for a steam turbine generator plant reflects the design concept for combined cycles to produce a total net output of 323 MW, at an efficiency of 50.0 percent (HHV). For this study, a single gas turbine is used in conjunction with one 1650 psig/1000 EF/1000 EF steam turbine.

The 400 MW single unit pulverized coal-fired electric generating station is based on a 3500 psig/1050 EF/1050 EF single reheat configuration. The HP turbine uses steam at 3515 psia and 1050 EF. The cold reheat steam is at 622 psia and 587 EF, which is reheated to 1050 EF before entering the IP turbine section. The performance reflects current state-of-the-art turbine adiabatic efficiency levels, boiler performance, and wet limestone FGD system capabilities. Overall, the plant produces a net output of 404 MW at a net efficiency of 40.1 percent on an HHV basis.

5.2 ECONOMICS

Evaluation of the capital costs provided in Sections 7.0 through 10.0, and the economic and financial results presented in Section 4.2, are summarized in Figures 5-3 and 5-4. The major difference between first and tenth year cases in the evaluation is the impact of real escalation for the fuels. The capital cost for both types of cases is considered to be identical.

The capital cost is recognized as the levelized carrying charges. The production cost for each technology consists of the fixed and variable operation and maintenance expenses and fuel cost. All values are expressed in cents per kilowatt hour based on the year 2005 plant startup. The detail results in Appendix B include the COE summary sheet for each technology.

The order of the components in Figure 5-3 was selected so that the impact of fuel cost for each of the plants can be compared. In addition, the fuel cost combined with the O&M results in the total production cost. This value is important since it determines the dispatch of the unit and therefore the actual capacity factor and load for the plants. In Figure 5-3 the fuel cost for all the plants except the natural gas combined cycle (NGCC) is very similar. This result is in direct relation to the plant net heat rate, except for the NGCC, which has the lowest heat rate at 6,827 Btu per kilowatt hour. The high NGCC value is related to the difference in fuel cost at $2.76 per 10^6 Btu for natural gas versus $1.27 for coal (January 1999 dollars).

The O&M costs for each technology have a general relationship to the capital cost of the corresponding plant. The higher capital cost for the plant results in higher costs for the maintenance of that plant. In the case of the KRW 400 MW versus the 200 MW plant, the unit value in cents for the 200 MW is greater but the absolute annual cost is smaller. This relationship can generally be attributed to the economy of scale associated with plant size (i.e., the 200 MW plant has 90 percent of the number of plant operators but 50 percent of the generation capability). The NGCC does not have significant consumables or any emission credits.

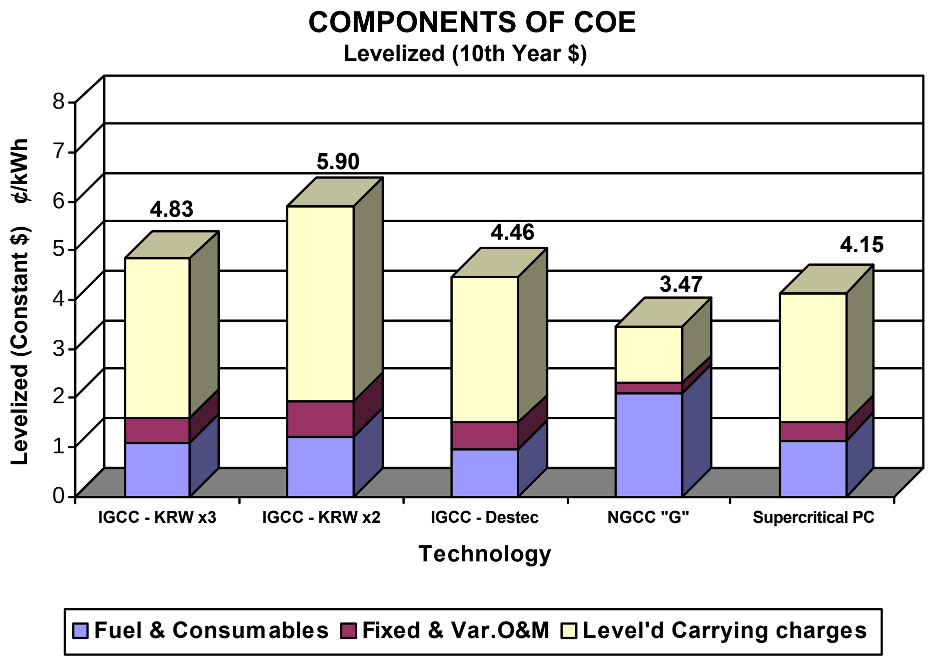

Figure 5-3

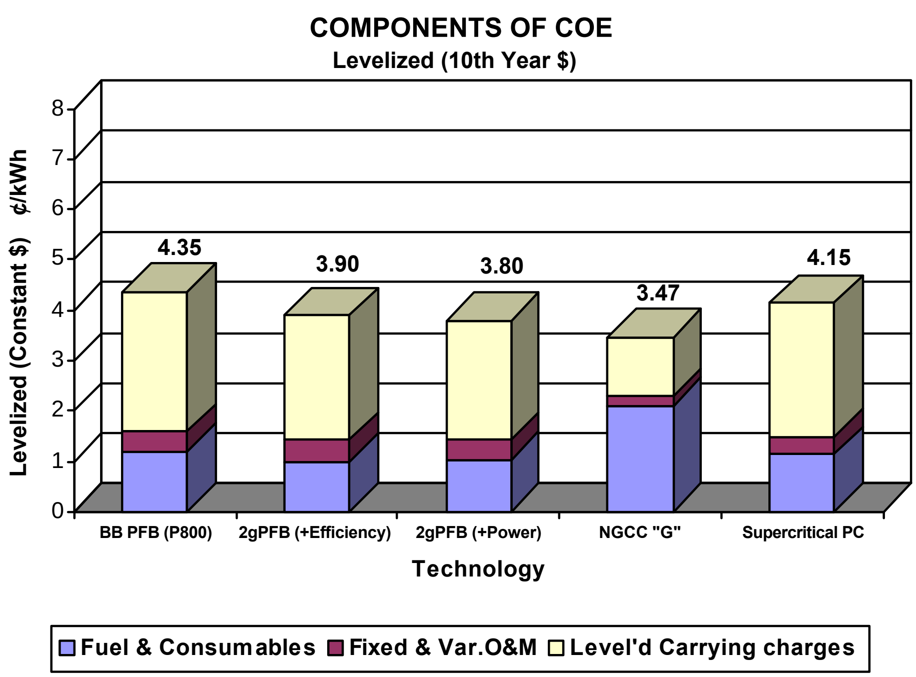

Figure 5-4

Examining the total production cost for each of the units, the sum of fuel and O&M, the values range from 1.56 cents for the 2g PFBC (power) plant to 2.10 cents for the NGCC plant in first-year dollars. In tenth-year dollars, the values range from 1.43 cents for the 2g PFBC (power) plant to 2.29 cents for the NGCC plant. The 2g PFBC, Destec IGCC, and supercritical PC plants have the lowest values at 1.56 cents to 1.65 cents in 2005 dollars and 1.43 cents to 1.50 cents in 2015 dollars. This similarity is due to slightly lower consumables but higher O&M for the Destec plant compared to the 2g PFBC and PC plants, which results in a total production cost, less fuel, slightly higher than for the 2g PFBC and PC plants. Overall, the PC plant has the lowest production cost, less fuel, but it also has the highest fuel cost of the low total production cost plants. The lower fuel cost for the Destec and 2g PFBC plants more than offsets the other production costs and results in the slightly lower total production cost relative to the PC plant.

Examination of the carrying charges reveals why the NGCC is currently a popular technology for capacity addition. While the production cost is somewhat higher than that of the other technologies, the total COE is the lowest due to the low fraction dependent on the capital investment.

5.3 ENVIRONMENTAL

The IGCC plants described in this report operate with lower emissions than the supercritical PC plant, and in some respects approach the performance of the natural gas burning combustion turbine combined cycle plant. Table 5-2 and Figures 5-5, 5-6, 5-7, and 5-8 present a comparison of the environmental performance for the technologies evaluated. Emissions performance is presented on the basis of thermal input (lb/10^6 Btu), annual output (lb/y) for operation at 65 percent and 85 percent capacity factors, and electrical production (lb/MWh). In specific terms, consider the following:

SO_2 Emissions - The IGCC plants discharge between 80 and 90 percent less SO_2 on an annual basis, compared to the reference PC plant, as illustrated in Figure 5-5 for operation at the 85 percent capacity factor. This is attributable to the more effective sulfur removal processes used in the gasifier and gas cleanup technologies. Sulfur removal capabilities of up to 97 percent are achievable for PC plants, but with increased capital and operating costs.

NOx Emissions - IGCC plant emissions of this pollutant are equivalent to the PC plant for the KRW gasifiers on a lb/10^6 Btu basis, but reduced on a lb/MWh basis due to the higher IGCC plant efficiency. The Destec plant NOx emissions are significantly lower than those of the PC and KRW plants, based on the different chemical environment in which the gasification occurs. In fact, the Destec is about equal to the NGCC in NOx production. NOx emissions from the KRW plants and the PC can be reduced to the levels exhibited by the NGCC and Destec by the addition of SCR and/or SNCR technology, at some additional expense.

Table 5-2a
Comparison of Environmental Performance

Fuel Power Plant Net Megawatts	Coal KRW 400 MW	Coal KRW 200 MW	Coal Destec 400 MW	Natural Gas NGCC 325 MW	Coal Pulverized Coal 400 MW
SO_2 Emissions, lb/10^6 Btu	0.07	0.07	0.06	Neg.	0.17
NOx Emissions, lb/10^6 Btu	0.16	0.16	0.08	0.10	0.20
Particulate Emissions, lb/10^6 Btu	0.004	0.004	0.004	Neg.	0.01
CO_2 Emissions, lb/10^6 Btu	207.2	207.2	200.4	118.0	203.2
Available hours/year:	8,760				
Capacity factor:	65.0%	65.0%	65.0%	65.0%	65.0%
SO_2 Emissions, ton/year	554	318	449	Neg.	1,686
NOx Emissions, ton/year	1,267	719	600	629	1,999
Particulate Emissions, ton/year	32	18	30	Neg.	97
CO_2 Emissions, ton/year	1,645,000	944,700	1,500,000	741,400	1,991,700
Capacity factor:	85.0%	85.0%	85.0%	85.0%	85.0%
SO_2 Emissions, ton/year	724	416	588	Neg.	2,205
NOx Emissions, ton/year	1,657	940	784	820	2,615
Particulate Emissions, ton/year	41	24	39	Neg.	127
CO_2 Emissions, ton/year	2,151,000	1,235,400	1,950,000	970,000	2,604,500
SO_2 Emissions, lb/MWh	0.51	0.56	0.45	Neg.	1.47
NOx Emissions, lb/MWh	1.16	1.27	0.60	0.68	1.74
Particulate Emissions, lb/MWh	0.03	0.03	0.03	Neg.	0.08
CO_2 Emissions, lb/MWh	1,501	1,675	1,508	806	1,731

Table 5-2b
Comparison of Environmental Performance

Fuel Power Plant Net Megawatts	Coal Circulating PFBC (1) 430 MW	Coal PCFBC (2) 400 MW	Coal Bubbling Bed PFBC 425 MW	Natural Gas NGCC 325 MW	Coal Pulverized Coal 400 MW
SO_2 Emissions, lb/10^6 Btu	0.23	0.23	0.23	Neg.	0.17
NOx Emissions, lb/10^6 Btu	0.10	0.10	0.20	0.10	0.20
Particulate Emissions, lb/10^6 Btu	0.004	0.004	0.004	Neg.	0.01
CO_2 Emissions, lb/10^6 Btu	206.0	205.8	206.5	118.0	203.2
Available hours/year:					
Capacity factor:	65.0%	65.0%	65.0%	65.0%	65.0%
SO_2 Emissions, ton/year	2,110	1,806	2,324	Neg.	1,686
NOx Emissions, ton/year	915	782	2,029	629	1,999
Particulate Emissions, ton/year	37	31	40	Neg.	97
CO_2 Emissions, ton/year	1,885,740	1,614,600	2,085,200	741,400	1,991,700
Capacity factor:	85.0%	85.0%	85.0%	85.0%	85.0%
SO_2 Emissions, ton/year	2,760	2,361	3,034	Neg.	2,205
NOx Emissions, ton/year	1,194	1,022	2,654	822	2,615
Particulate Emissions, ton/year	48	41	53	Neg.	127
CO_2 Emissions, ton/year	2,465,970	2,111,500	2,726,800	970,000	2,604,500
SO_2 Emissions, lb/MWh	1.72	1.67	1.92	Neg	1.47
NOx Emissions, lb/MWh	0.74	0.72	1.68	0.68	1.74
Particulate Emissions, lb/MWh	0.03	0.03	0.03	Neg.	0.08
CO_2 Emissions, lb/MWh	1,539	1,497	1,724	806	1,731

1. Pressurized circulating fluidized bed combustion with high output
2. Pressurized circulating fluidized bed combustion with high efficiency

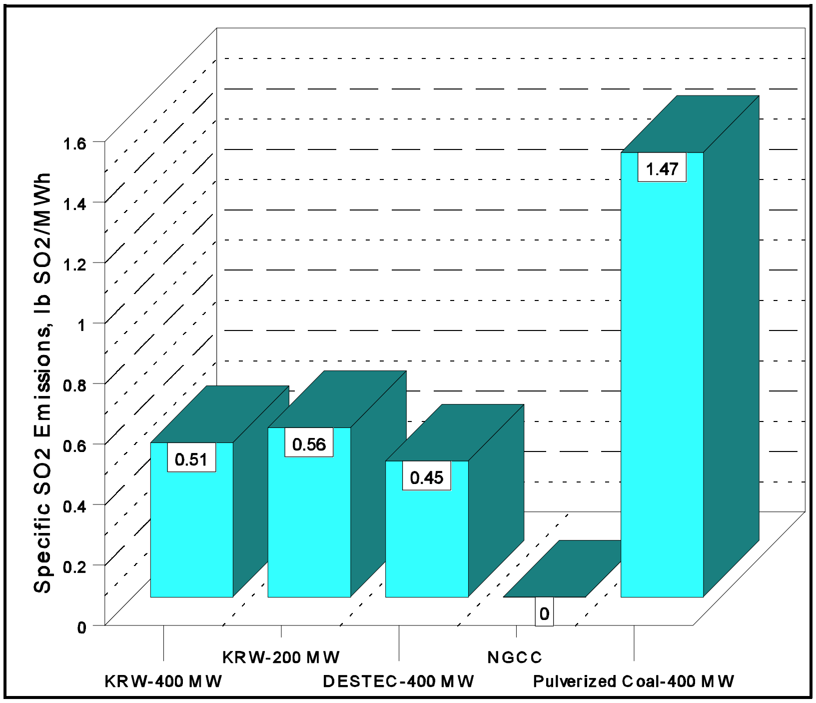

Figure 5-5a
Output-Specific SO_2 Stack Emissions

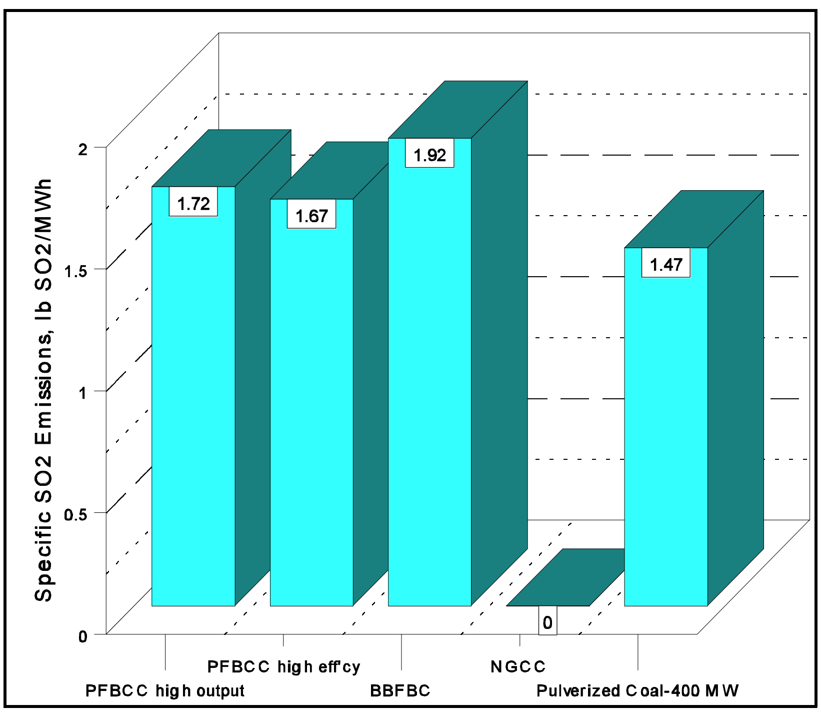

Figure 5-5b
Output-Specific SO_2 Stack Emissions

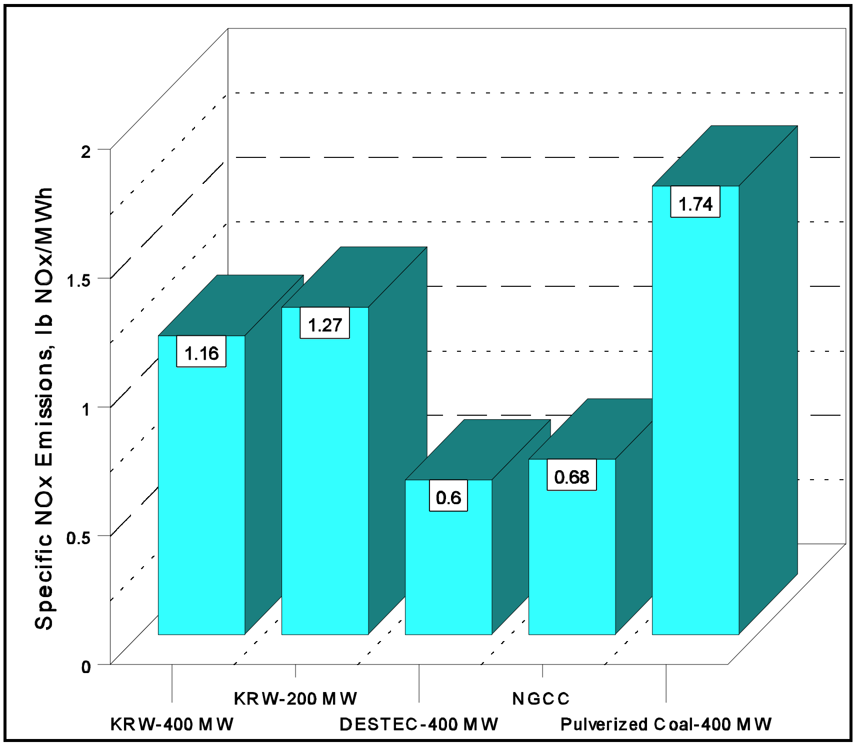

Figure 5-6a
Output-Specific NOx Stack Emissions

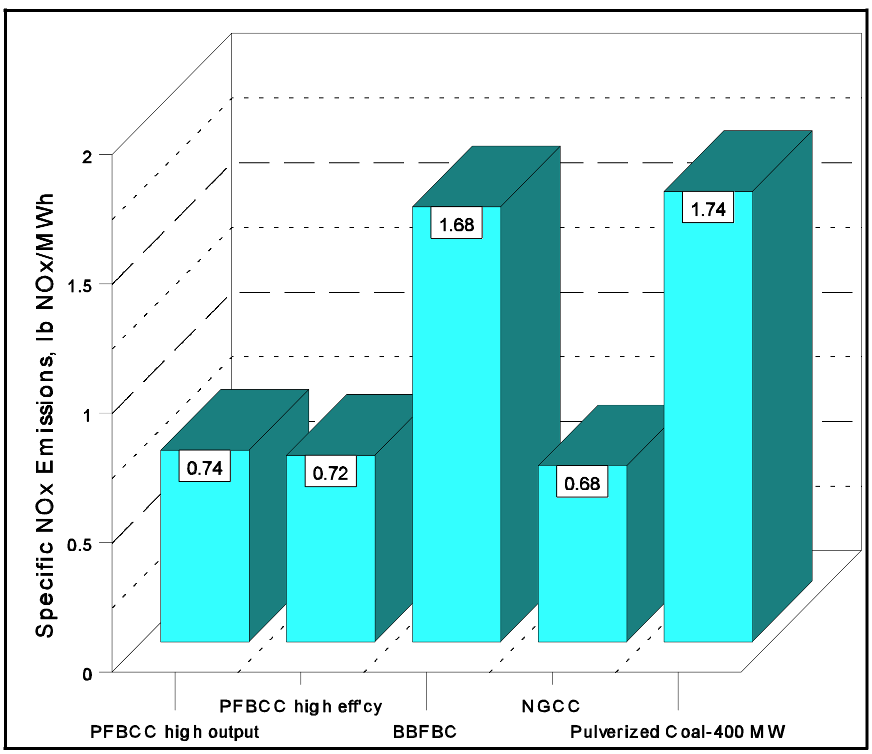

Figure 5-6b
Output-Specific NOx Stack Emissions

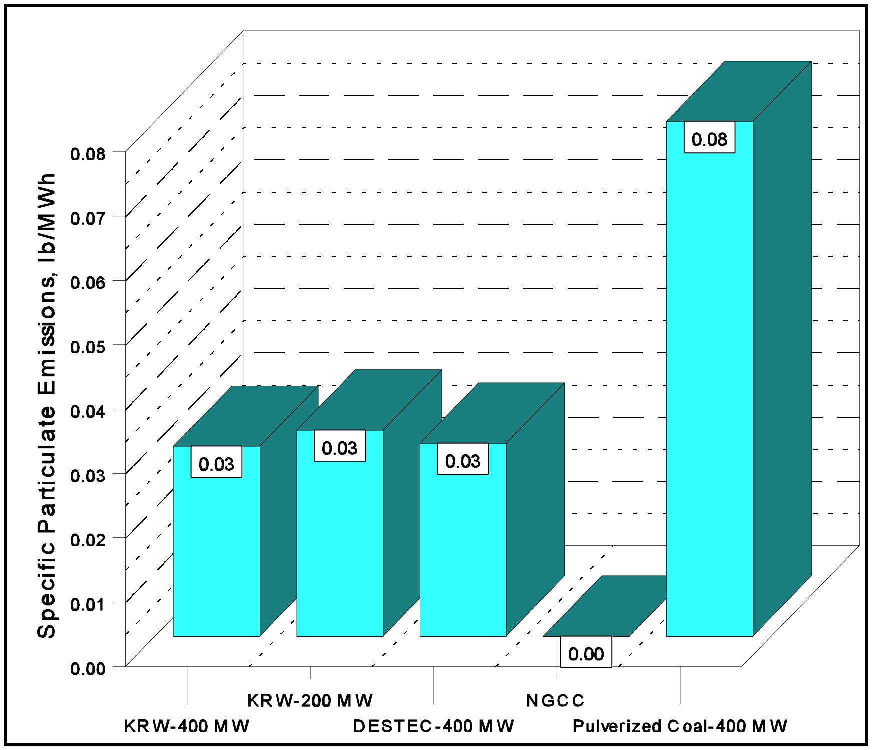

Figure 5-7a
Output-Specific Particulate Stack Emissions

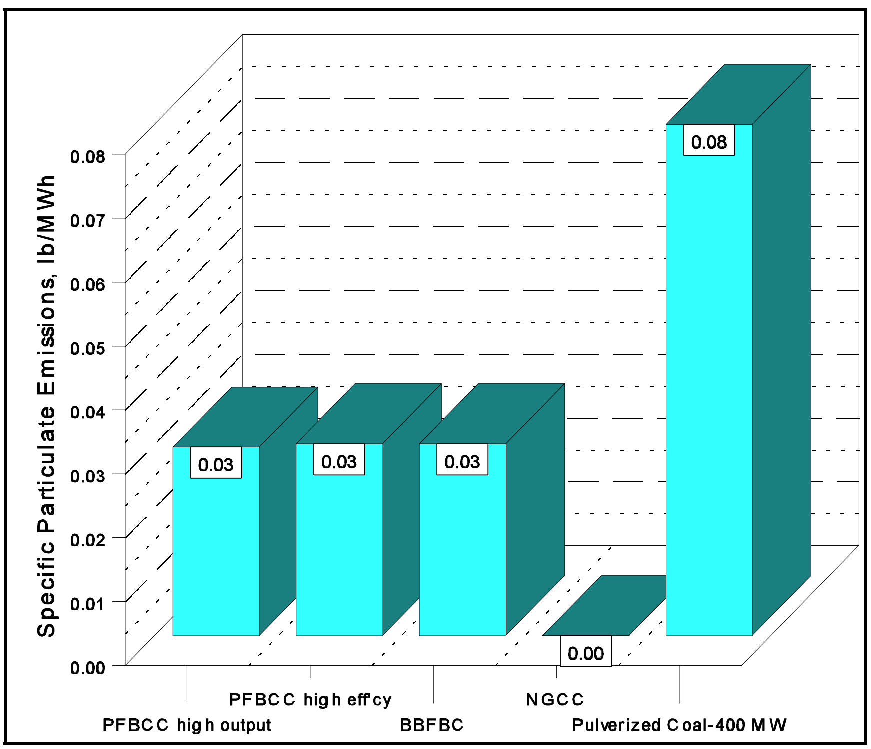

Figure 5-7b
Output-Specific Particulate Stack Emissions

Particulate Emissions - IGCC plant emissions for particulate are equivalent to the PC reference plant in terms of thermal input, annual production, and on a MWh basis. However, when compared to the NGCC, coal-based power plants cannot compare.

CO_2 Emissions - In the area of non-regulated emissions of CO_2, all the coal-based systems are equivalent on a production basis of lb/MWh at 85 percent capacity factor, as indicated in Figure 5-8, with a slight advantage given to the better performing IGCC systems. As with particulate emissions, the NGCC outperforms the coal-fired alternatives in all measures of CO_2 emissions.

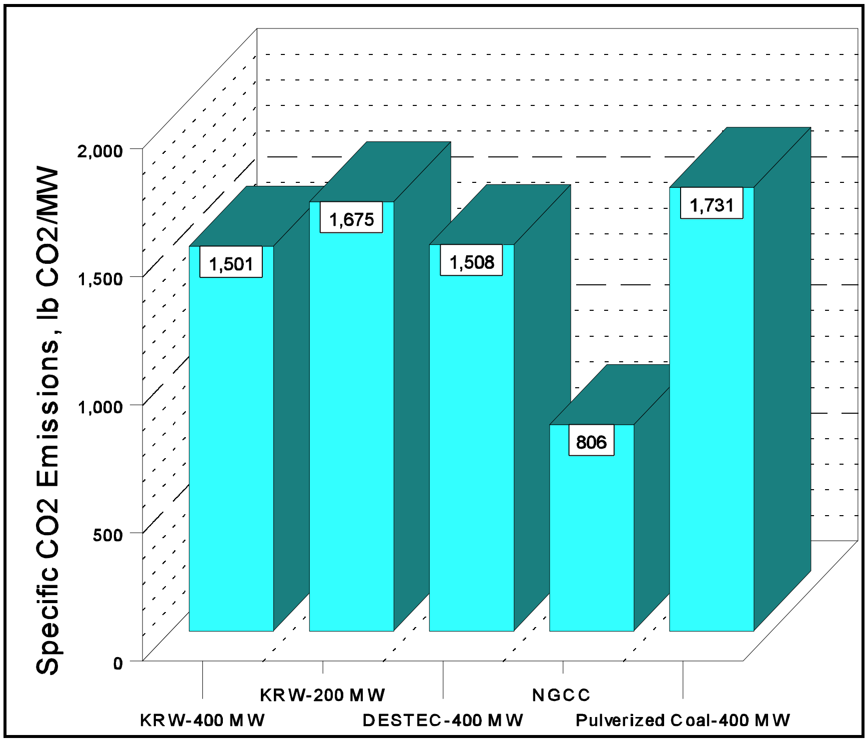

Figure 5-8a
Output-Specific CO_2 Stack Emissions

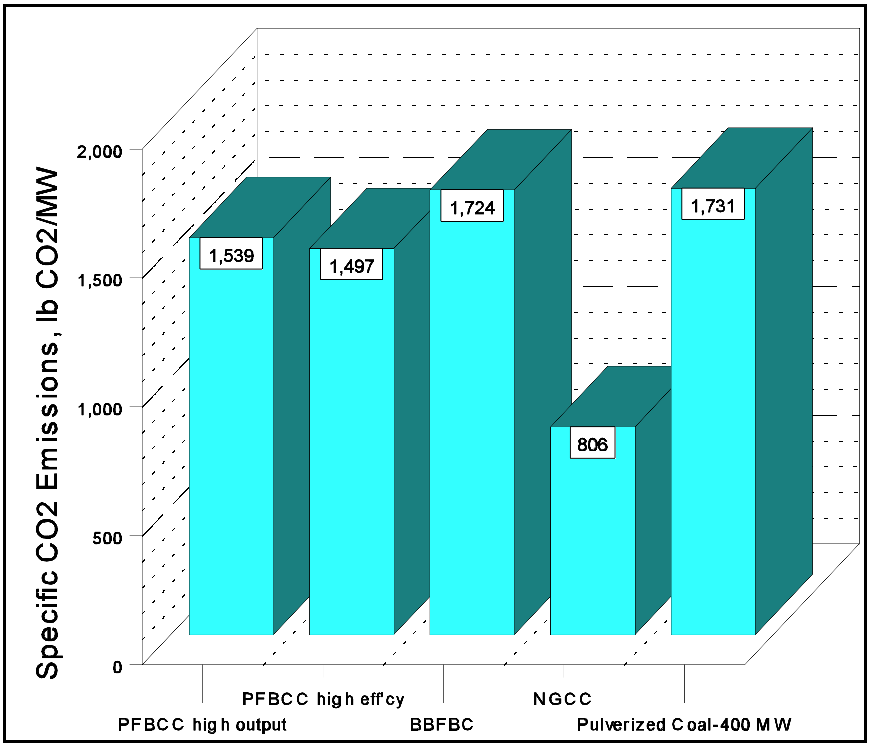

Figure 5-8b
Output-Specific CO_2 Stack Emissions

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APPENDIX A

Environmental Regulation, Permitting and Licensing

APPENDIX A
ENVIRONMENTAL REGULATION, PERMITTING AND LICENSING

The clean coal technology (CCT) powered project must be designed with environmental emissions levels that meet or exceed the requirements of U.S. Environmental Protection Agency (EPA) environmental regulations, state regulations, and local regulations. This Appendix briefly describes some of the environmental regulations applicable to CCT powered or repowered plants.

A.1 AIR QUALITY REGULATIONS

The air emission requirements under the Clean Air Act Amendments of 1990 (CAAA) Title I - Nonattainment, and Title IV - Acid Rain, are listed in Exhibit 1 at the end of this Appendix.

Repowering an existing power plant requires meeting increasingly stringent environmental requirements outlined in the CAAA. The acid rain requirements under Title IV include restrictions of SO_2 emissions through the use of an allowance program, which places an annual limit on SO_2 emitted by a unit in tons per year. Allowances are assigned by the EPA to the unit in two phases. Units affected by Title IV, Phase I are listed in the CAAA. During Phase II of Title IV, all utility generating units are affected.

Owners of affected units under Title IV can reduce emissions below those allocated and either apply the unused allowances to other units that they own or sell their unused allowances. Plants without allowances, including all plants starting up after November 15, 1990 (the date of enactment of the CAAA), and those with insufficient allowances will have to obtain them from allowance owners or from the EPA. If a CCT unit's emission rate is less than 1.20 lb/MMBtu, excess allowances should be earned by a repowered unit and could be used at other plants (or sold).

From January 1, 1995, NOx emissions from units affected by Phase I are limited under the Title IV acid rain program for dry-bottom, tangential-fired boilers and for dry-bottom, wall-fired boilers. NOx emission limits for units affected by Phase II and other types of Phase I boilers are to be promulgated January 1997 and effective starting January 2000.

The requirements for areas that are not meeting ambient air quality standards for ozone under Title I of the CAAA include NOx emission control at existing major stationary sources that is considered to be achievable with the installation of reasonably available control technology (RACT). In order for the Northeast Ozone Transport Region (OTR) to meet ozone ambient air quality standards, further NOx controls beyond RACT are anticipated at existing facilities. The NOx limits beyond RACT would be effective during the ozone season, i.e., from May 1 through September 30. New major stationary sources in nonattainment areas would be required to install lowest achievable emission rate (LAER) technology and obtain emission offsets for its emissions at a ratio greater than one for one.

Some states have also proposed air regulations regarding stationary combustion installations that provide performance standards for utility life-extension projects. These regulations pertain to utility boilers operated beyond their useful life (e.g., beyond 45 years). Some of the proposed life extension regulations would require meeting New Source Performance Standards (NSPS); others would require:

- SO_2 emissions be limited to 0.50 lb/MMBtu, or less,
- NOx emissions be limited to the best available control technology (BACT), which will require an analysis of the various NOx controls available at the time,
- Particulate matter emissions be limited to 0.03 lb/MMBtu, or less, and
- The allowable heat rate for pulverized-coal boilers, atmospheric fluidized-bed boilers, and pressurized fluidized-bed boilers is expected to be less than or equal to 9,300 Btu/kWh.

In general, any emission increases also need to be reviewed for major net emissions increases for the applicability of new source review requirements for the repowering project. Repowering using clean coal demonstration projects funded by DOE are exempt from other air quality regulations (such as NSPS or Prevention of Significant Deterioration [PSD] regulations) if there is no significant increase in potential emissions, no increase in maximum hourly emissions, and the repowering is environmentally beneficial. This will require that air emissions decrease from existing plant operation to the repowered facility.

PSD requirements are applicable to new major stationary sources being located in areas that are meeting National Ambient Air Quality Standards (NAAQS). The PSD requirements are developed around the concept of installing BACT. By their nature, the clean coal technologies should qualify as BACT.

Exhibit 2 represents the changing environmental requirements for an existing Phase I affected dry-bottom tangential-fired unit, at a plant located in the OTR with environmental upgrades required to meet more stringent state requirements, as well as the general emission requirements expected in most other locations. At most other repowering sites, the inherent low-NOx emission characteristics of the clean coal technologies will prove suitable for operation without post-combustion NOx control technologies.

Exhibit 3 presents future ambient air quality standards being considered by the EPA. These uncertainties cause concerns, and will have to be addressed if they become an EPA standard. In fact, with the more stringent standard, it is likely to affect existing sources as well as future sources. The future sources will use the emission offsets from the existing sources against new sources. There has not been any indication of the direction that EPA is heading, and it is not possible to anticipate what those future requirements may be, or the effect. But it is safe to say that the future emissions from a new or repowered plant with a CCT will be less than the emissions from the existing plant.

PM-2.5 NAAQS

In the area of particulates, EPA is making more stringent the current particulate standard from PM_{10} down to $PM_{2.5}$ and smaller. The characteristics, sources, and potential health effects of larger or "coarse" fraction particles (from 2.5 to 10 micrometers in diameter) and smaller or "fine" particles (smaller than

2.5 micrometers in diameter) are very different. Coarse particles come from sources such as windblown dust from the desert or agricultural fields and dust kicked up on unpaved roads by vehicle traffic. Fine particles are generally emitted from activities such as industrial and residential combustion and from vehicle exhaust. Fine particles are also formed in the atmosphere when gases such as sulfur dioxide, nitrogen oxides, and volatile organic compounds, emitted by combustion activities, are transformed by chemical reactions in the air.

EPA revised the primary (health-based) PM standards by adding a new annual $PM_{2.5}$ standard set at 15 micrograms per cubic meter ($\mu g/m^3$) and a new 24-hour $PM_{2.5}$ standard set at 65 $\mu g/m^3$. The final rule establishes a new form for the annual $PM_{2.5}$ standard. Areas will be in compliance with the new annual $PM_{2.5}$ standard when the 3-year average of annual arithmetic mean $PM_{2.5}$ concentrations, from single or multiple community-oriented monitors, is less than or equal to 15 $\mu g/m^3$. For the new 24-hour $PM_{2.5}$ standard, the form is based on 98th percentile of 24-hour $PM_{2.5}$ concentrations in a year (averaged over 3 years), at the population-oriented monitoring site with highest measured values in an area.

Based on its assessment of the health and other available information, EPA retains the annual PM_{10} standard of 50 $\mu g/m^3$ to protect against effects from both long- and short-term exposure to coarse fraction particles. EPA is adjusting the PM_{10} 24-hour standard of 150 $\mu g/m^3$ by changing the form of the standard. EPA is replacing the one-expected-exceedance form with a 99th percentile form, averaged over 3 years, to protect against short-term exposure to coarse fraction particles.

EPA sets the secondary standards identical to the final primary standards, in conjunction with establishment of a regional haze program. This approach will provide appropriate protection against the welfare effects associated with particulate pollution including visibility impairment, soiling, and material damage.

The Clean Air Act requires that EPA make designation determinations (i.e., attainment, nonattainment, or unclassifiable) within two to three years of revising a standard. Since EPA will not have adequate $PM_{2.5}$ monitoring data for that purpose, in 1999 EPA will issue "unclassifiable" designations for $PM_{2.5}$. These designations will not trigger the planning or control requirements. A comprehensive monitoring network (comprised of 1,500 monitors) to determine ambient fine particle concentrations across the country will be phased in over a 3- to 4-year period. In 1998, all metropolitan areas with at least 500,000 people are required to have at least one core monitor, and each State is required to have at least two additional monitors. The new $PM_{2.5}$ ambient monitoring network will consist of core community-oriented monitors; many will be required to sample every day (or continuously), while supplementary monitors will be allowed to sample less frequently. The supplementary monitors will provide coverage in small cities and rural areas, some of which are intended to study the long-range transport of fine particles. Three years of acceptable monitoring data will be available from the earliest monitors by the spring of 2001, and 3 years of data will be available from all monitors in 2004. Allowing time for data analysis, State Governors and EPA will not be able to make the first determinations about which areas should be redesignated from unclassifiable to nonattainment status until at least 2002. States will have 3 years from date of being designated nonattainment (or until between 2005 and 2008) to develop pollution control plans and submit them to EPA showing how they will meet the new standards. Areas will then have up to 10 years from their designation as nonattainment to attain the $PM_{2.5}$ standards with the possibility of two 1-year extensions.

Available information indicates that, nearly one-third of the areas projected to violate the new $PM_{2.5}$ standards, primarily in the Eastern United States, could come into compliance as a result of the regional SO_2 emission reductions already mandated under the Clean Air Act's acid rain program, which will be fully implemented between 2000 and 2010. As detailed $PM_{2.5}$ air quality data and data on the chemical composition of $PM_{2.5}$ in different areas become available, EPA will work with the states to analyze regional strategies that could reduce $PM_{2.5}$ levels. If further cost-effective reductions will help areas meet the new standards, EPA will encourage states to work together to use a cap-and-trade approach similar to that used to curb acid rain. The EPA will also encourage states to coordinate their $PM_{2.5}$ control strategy development and efforts to protect regional visibility.

There is a strong desire to drive the development of new technologies with the potential of greater emission reduction at less cost. It was agreed that $10,000 per ton of emission reduction is the high end of the range of reasonable cost to impose on sources. Consistent with the state's ultimate responsibility to attain the standards, the EPA will encourage the states to design strategies for attaining the PM and ozone standards that focus on getting low-cost reductions and limiting the cost of control to under $10,000 per ton for all sources.

A.2 WATER QUALITY REGULATIONS

Water use, thermal discharge, and liquid waste discharges for the CCT powered plant will meet federal and local regulations for magnitude and contaminant limits. Specifically, the discharge would be required to meet applicable effluent guidelines and water quality standards. An increase in water usage by a CCT would require increased water allocations, which could be a concern in arid states. Also, a change in thermal discharge to a water body could violate water temperature limits provided by the National Pollutant Discharge Elimination System (NPDES) permit. Typical repowering and environmental upgrade are not expected to increase the steam turbine exhaust flow, so no increase in the flow or temperature of discharge water is expected.

There may be minor changes to other wastewater streams internal to the plant, such as those associated with runoff from the ash and sorbent storage/handling systems. Effluent limitations applicable to the CCT powered plant are expected to be similar to those that currently apply to existing facilities. It is not expected that any repowering concept will result in significant water impacts that would require the use of different wastewater treatment systems or cooling towers. Of course, the wastewater characteristics of the effluent from the repowered unit will need to be investigated for any significant changes in quantity or quality.

A.3 SOLID WASTE DISPOSAL REGULATIONS

Changes to the characteristics of the waste generated by a CCT project will need to be investigated. The quantity of ash generated by a repowering project will need to be compared to that of the existing plant. In some cases, the quantity of ash is expected to increase as a result of the use of sorbent material to control SO_2 emissions. The quality of the waste may also change as a result of the repowering project. The characteristics of the ash generated by the repowered unit will need to be identified and compared to the ash characteristics of the existing plant. Most states require the use of the toxicity characteristic leaching procedure (TCLP) test to evaluate if the waste generated is considered to be hazardous or not. It is anticipated that it is not hazardous.

There is also a possibility that there could be an increase in the quantity of waste generated by the repowering project, mostly from the flue gas desulfurization systems added to the plant for sulfur control. The impact of these increases, if any, will need to be considered. Most states are also requiring utility waste disposal areas to be lined, with leachate collected, tested, and treated, if necessary.

A.4 PERMITTING, LICENSING, AND REGULATORY APPROVAL REQUIREMENTS

Exhibit 4 is a preliminary list of activities and permits often required for a power plant project. The specific applicability of each is established when details of the project develop.

For a repowering project, the necessary construction permits would usually be expected within 18 months of the start of the project, provided design information is available to support the preparation of applications. This permitting period represents a considerable time savings over the permitting needed to develop a greenfield location. Similar projects planned for a greenfield location are expected to take significantly longer because of the need for siting approval and approval of the transmission line.

Exhibit 1
CAAA of 1990 Summary

TITLE	PHASE	POLL	DESCRIPTION	SOURCES AFFECTED	EMISSION LIMITS	REGS. DUE	IMPLEMENT DATE
I			OZONE NON-ATTAINMENT (NOx) (OTR sources only)				
	1	NOx	RACT	All Major Sources (1)			5/31/95
	2	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	Northern Zone: RACT		5/1/99
	2	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	NE Inner Zone: 65% Red.or 0.2 lb/MMBtu		5/1/99
	2	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	NE Outer Zone: 55% Red. or 0.2 lb/MMBtu		5/1/99
	3	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	Northern Zone: 55% Red. or 0.2 lb/MMBtu		5/1/03
	3	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	NE Inner Zone: 75% Red. or 0.15 lb/MMBtu		5/1/03
	3	NOx	Meet ambient air qual. stds. (2)	>250 MMBtu/h heat input &>15 MW	NE Outer Zone: 75% Red. or 0.15 lb/MMBtu		5/1/03
IV			**ACID DEPOSITION**				
	1	NOx	LNB Technology (3)	Group 1 175 T-fired & dry bott/wall-fired blrs (3)	T&Wall-fired: 0.45/0.50 lb/MMBtu		1/1/95
	1	SO_2		Units >100 MW & emitting> 2.5 lb/MMBtu	2.5 lb/MMBtu		1/1/95
	2	NOx	Best system in cost comparable to Ph1LNB (3)	Group 2 blrs.>25t NOx/yr, 2000 units/785 plts (3)		1/1/97	1/1/00
2	SO_2		Units > 25 MW	1.2 lb/MMBtu		1/1/00	

Notes: (1) In PA facilities emitting 100 tons or more of NOx/year & in NJ facilities emitting 25 tons or more of NOx/year.
(2) Applicable in the 5-month period (May-Sept) with RACT year around.
(3) Affects utilities outside the Ozone Transport Region (OTR) as Title I is more stringent than Title IV for OTR affected utilities.
(4) Northeast Ozone Region is comprised of northern Virginia through Maine including Washington DC.
Inner Zone: (Amtrak Corridor) Washington DC. to north of Boston, includes contiguous moderate, serious, and severe non-attainment areas.
Outer Zone: Remainder of New York and Pennsylvania
Northern Zone: New Hampshire, Vermont, Maine and upstate New York

Exhibit 2
Summary of Current and Expected Coal-Fired Air Emissions Limitations

Pollutant	Coal-fired plant stack emissions will be less than:				
	Through Dec 31, 1994*	**After Jan 1, 1995**	**After Year 1999**	**After Year 2000**	**After Year 2003**
Sulfur Dioxide (SO_2)	5.00 lb/MMBtu 3.80 lb/MMBtu (Annual Average)	2.50 lb/MMBtu Title IV	2.50 lb/MMBtu Title IV	0.50 lb/MMBtu requirements for life-extension units in example state Note: Would be 1.20 lb/MMBtu if in another state, Title IV	0.50 lb/MMBtu requirements for life-extension units in example state Note: Would be 1.20 lb/MMBtu if in another state, Title IV
Nitrogen Oxides (NOx)	0.70 lb/MMBtu	0.42 lb/MMBtu Title I Note: Would be 0.45 lb/MMBtu if not in the ozone transport region, Title IV	0.20 lb/MMBtu Title I Note: Would be 0.45 lb/MMBtu if not in the ozone transport region, Title IV	0.20 lb/MMBtu Title I Note: Would be 0.45 lb/MMBtu if not in the ozone transport region, Title IV	0.15 lb/MMBtu expected, Title I Note: Would be 0.45 lb/MMBtu if not in the ozone transport region, Title IV
Particulate Matter (PM)	0.22 lb/MMBtu	0.22 lb/MMBtu	0.22 lb/MMBtu	0.03 lb/MMBtu requirements for life-extension units in the example state	0.03 lb/MMBtu requirements for life-extension units in the example state

Notes:
* Emission limitations through December 31, 1994 are existing permit limits.

The unit is assumed to be located in the OTR, an existing Phase I affected dry-bottom tangential-fired unit. This exhibit represents the changing environmental requirements for at a plant with environmental upgrades required to meet more stringent state life extension requirements. It also represents the general emission requirements expected in most other locations.

Exhibit 3
National Ambient Air Quality Standards (Existing and Proposed)
micrograms per cubic meter (ppm)

Criteria Pollutant	Existing Primary	Existing Secondary	Proposed Standard	Pollutant
Particulate Matter 10 Microns (PM-10)				
Annual	50	50		
24 hour	150	150		
Particulate Matter PM-2.5				
Annual	15	15		
24 hour	65	65		
Sulfur Dioxide (SO_2)				Sulfur Dioxide (SO_2)
Annual	80 (0.03 ppm)			
24 hour	365 (0.14 ppm)			
3 hour		1,300 (0.5 ppm)		
			0.60 ppm	5 minutes
Carbon Monoxide (CO)				
8 hour	10,000 (9 ppm)			
1 hour	40,000 (35 ppm)			
Nitrogen Dioxide (NOx)				
Annual	100 (0.053 ppm)	100 (0.053 ppm)		
Ozone (O_3)				
1 hour	235 (0.12 ppm)	235 (0.12 ppm)		
8 hour		0.08 ppm		
Lead (Pb)				
Quarterly	1.5	1.5		
				Acid Deposition
			3.5 kilograms per hectare	

Source: US EPA, Title 40, Code of Federal Regulations Part 50 (40 CFR 50), National Primary and Secondary Ambient Air Quality Standards

Note: Primary standards define the levels necessary to protect the public health with an adequate margin of safety.
Secondary standards, generally more stringent than primary standards, define the levels necessary to protect the public welfare and property from any known or anticipated adverse effects of a pollutant.

Exhibit 4
Preliminary List of Required Approvals

Approval	Agency	Activity
Certificate of Environmental Compatibility and Public Need	PSC	New steam electric generating facilities 50 MW or more
Permit to Construct Sources of Air Contamination	DEC	Construction or modification of an air contaminant source or an indirect source
Certificate to Operate for Sources of Air Contamination	DEC	Operation of an air contaminant source or an indirect source
State Pollutant Discharge Elimination System Permit	DEC	Any proposed or existing discharge of sewage, industrial wastes, or other wastes to surface water or groundwater
Water Supply Permit	DEC	Water supply and water allocation
Construction Permit	DEC	Construction or modification to solid waste management facility, including storage, transfer, processing, recovering, reclaiming and disposal
Operating Permit	DEC	Operating a solid waste management facility, including storage, transfer, processing, recovering, reclaiming and disposal
Hazardous Waste Facility Permit	DEC	Construction, modification, or operation of a hazardous waste management facility
Freshwater Wetlands Permit	DEC	Any activity in a wetlands or within 100 feet of a wetland boundary affecting a wetland
Protection of Waters Permit	DEC	Any activity in or affecting navigable water of the states including any marshes, estuaries and wetlands adjacent to navigable water
Corps of Engineers Permit	COE	Any activity in or affecting navigable water of the United States
401 Certification	DEC	Required for any federal permit indicating that approval will not cause a violation of state water quality standards
Construction in Flood Hazard Area Permit	DEC	Construction within 100-year flood plain
Building Permit, Zoning Approval	Local	Any building permit required for occupancy of a structure including electrical, plumbing, HVAC, fire protection, life safety

Notes: PSC - State Public Service Commission
DEC - State Department of Environmental Conservation
COE - U.S. Army Corps of Engineers

APPENDIX B

Economic and Financial Results

IGCC - KRW Air-Blown 400 MWe

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC - KRW x 3		
Plant Size:	384.9 (MW,net)	HeatRate:	7,247 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	3.5 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		387,268	1006.1
Engineering(incl.C.M.,H.O.& Fee)		37,541	97.5
Process Contingency		34,630	90.0
Project Contingency		80,086	208.1
TOTAL PLANT COST(TPC)		$539,525	1401.7
TOTAL CASH EXPENDED	$539,525		
AFDC	$56,195		
TOTAL PLANT INVESTMENT(TPI)		$595,720	1547.7
Royalty Allowance			
Preproduction Costs		14,536	37.8
Inventory Capital		4,021	10.4
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.2
TOTAL CAPITAL REQUIREMENT(TCR)		$614,726	1597.1

OPERATING & MAINTENANCE COSTS (1999 Dollars)	$x1000	$/kW-yr
Operating Labor	4,467	11.6
Maintenance Labor	3,403	8.8
Maintenance Material	5,104	13.3
Administrative & Support Labor	1,967	5.1
TOTAL OPERATION & MAINTENANCE	$14,942	38.8
FIXED O & M		33.00 $/kW-yr
VARIABLE O & M		0.08 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	$x1000	¢/kWh
Water	815	0.03
Chemicals	4,510	0.16
Other Consumables		
Waste Disposal	2,632	0.09
TOTAL CONSUMABLE OPERATING COSTS	$7,957	0.28
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$26,378	0.92

	1st Year (2005 $)		Levelized (10th.Year $)	
PRODUCTION COST SUMMARY		¢/kWh		¢/kWh
Fixed O & M	33.0/kW-yr	0.44	33.0/kW-yr	0.44
Variable O & M		0.08		0.08
Consumables		0.28		0.28
By-product Credit				
Fuel		0.85		0.79
TOTAL PRODUCTION COST		1.65		1.59
LEVELIZED CARRYING CHARGES(Capital)			241.2/kW-yr	3.24
LEVELIZED (10th.Year) BUSBAR COST OF POWER				4.83

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC - KRW x 3			
Unit Size:/Plant Size:	384.9	MW,net	384.9	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	7,247	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	3.5	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		01:08 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC - KRW x 3					
Plant Size:	384.9 MW,net	**Estimate Type:** Conceptual		**Cost Base (Jan)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,429		1,363	95		$3,888	311		840	$5,039	13
1.2	Coal Stackout & Reclaim	3,139		874	61		$4,074	326		880	$5,280	14
1.3	Coal Conveyors & Yd Crush	2,918		865	61		$3,844	307		830	$4,981	13
1.4	Other Coal Handling	764		200	14		$978	78		211	$1,267	3
1.5	Sorbent Receive & Unload	66		25	2		$93	7		20	$120	0
1.6	Sorbent Stackout,Storage & Reclaim	2,094		704	49		$2,847	228		615	$3,690	10
1.7	Sorbent Conveyors	1,263	110	337	24		$1,734	139		375	$2,247	6
1.8	Other Sorbent Handling	329	72	212	15		$629	50		136	$815	2
1.9	Coal & Sorbent Hnd.Foundations		2,952	4,204	294		$7,450	596		2,012	$10,058	26
	SUBTOTAL 1.	**$13,002**	**$3,134**	**$8,785**	**$615**		**$25,536**	**$2,043**		**$5,918**	**$33,497**	**87**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	750	117	287	20		$1,174	94		254	$1,522	4
2.2	Prepared Coal Storage & Feed	258	58	46	3		$366	29		79	$474	1
2.3	Coal & Sorbent Feed System	5,643		3,086	216		$8,945	1,073	447	1,570	$12,035	31
2.4	Misc.Coal Prep & Feed	365	249	916	64		$1,594	128		430	$2,152	6
2.5	Sorbent Prep Equipment	817	72	336	24		$1,249	100		270	$1,619	4
2.6	Sorbent Storage & Feed	215		51	4		$269	22		58	$349	1
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		773	670	47		$1,489	119		402	$2,011	5
	SUBTOTAL 2.	**$8,049**	**$1,269**	**$5,391**	**$377**		**$15,087**	**$1,565**	**$447**	**$3,063**	**$20,161**	**52**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	967	3,759	1,023	72		$5,821	466		943	$7,229	19
3.2	Water Makeup & Pretreating	353	37	206	14		$611	49		132	$792	2
3.3	Other Feedwater Subsystems	575	215	199	14		$1,004	80		217	$1,301	3
3.4	Service Water Systems	27	58	208	15		$309	25		67	$400	1
3.5	Other Boiler Plant Systems	1,154	466	1,190	83		$2,893	231		781	$3,905	10
3.6	FO Supply Sys & Nat Gas	96	181	349	24		$650	52		140	$843	2
3.7	Waste Treatment Equipment	704		419	29		$1,152	92		249	$1,493	4
3.8	Misc. Power Plant Equipment	1,845	250	935	65		$3,094	248		1,003	$4,344	11
	SUBTOTAL 3.	**$5,720**	**$4,967**	**$4,529**	**$317**		**$15,533**	**$1,243**		**$3,531**	**$20,307**	**53**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries	32,949		18,011	1,261		$52,221	6,267	7,833	9,948	$76,269	198
4.2	High Temperature Cooling	4,327		2,365	166		$6,858	823	1,029	1,306	$10,016	26
4.3	Recycle Gas System	2,838		1,552	109		$4,499	540	675	857	$6,570	17
4.4	Booster Air Compression	7,160		1,817	127		$9,104	1,092	1,366	1,734	$13,296	35
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment		773	324	23		$1,120	134		188	$1,443	4
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations		3,090	1,861	130		$5,081	406		1,372	$6,859	18
	SUBTOTAL 4.	**$47,274**	**$3,863**	**$25,931**	**$1,815**		**$78,883**	**$9,263**	**$10,902**	**$15,406**	**$114,454**	**297**

	Client:	DEPARTMENT OF ENERGY							**Report Date:**		23-Jul-99	
	Project:	TASK 9-3 CCT Evaluation Guide									01:08 PM	

TOTAL PLANT COST SUMMARY

Case: IGCC - KRW x 3

Plant Size: 384.9 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Gas Desulfurization(Trans.Reactor)	7,944		4,343	304		$12,591	1,511	1,889	4,797	$20,787	54
5.2	Sulfur Recovery (Sulfator Sys.)	17,697		9,678	677		$28,052	3,366	4,208	10,688	$46,314	120
5.3	Chloride Guard	6,347		1,536	108		$7,991	959	1,998	2,737	$13,685	36
5.4	Particulate Removal	18,720		2,305	161		$21,187	2,542	5,297	5,805	$34,831	90
5.5	Blowback Gas Systems	2,243	3,216	1,867	131		$7,457	895	1,864	2,043	$12,259	32
5.6	Fuel Gas Piping		1,655	1,282	90		$3,026	242		817	$4,086	11
5.9	HGCU Foundations		299	203	14		$516	41		139	$697	2
	SUBTOTAL 5.	**$52,952**	**$5,170**	**$21,213**	**$1,485**		**$80,819**	**$9,557**	**$15,255**	**$27,026**	**$132,658**	**345**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	46,514		2,832	198		$49,544	3,963	7,432	6,094	$67,033	174
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		139	162	11		$312	25		101	$438	1
	SUBTOTAL 6.	**$46,514**	**$139**	**$2,994**	**$210**		**$49,855**	**$3,988**	**$7,432**	**$6,195**	**$67,470**	**175**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,707		2,009	141		$15,857	1,269		856	$17,982	47
7.2	HRSG Accessories											
7.3	Ductwork		592	519	36		$1,147	92		248	$1,487	4
7.4	Stack	1,834		710	50		$2,594	208		420	$3,222	8
7.9	HRSG,Duct & Stack Foundations		91	92	6		$189	15		51	$255	1
	SUBTOTAL 7.	**$15,541**	**$683**	**$3,330**	**$233**		**$19,787**	**$1,583**		**$1,575**	**$22,946**	**60**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	14,244		2,395	168		$16,806	1,345		908	$19,058	50
8.2	Turbine Plant Auxiliaries	97		229	16		$342	27		55	$425	1
8.3	Condenser & Auxiliaries	2,498		705	49		$3,253	260		351	$3,865	10
8.4	Steam Piping	3,547		1,907	133		$5,587	447		905	$6,939	18
8.9	TG Foundations		187	596	42		$825	66		223	$1,114	3
	SUBTOTAL 8.	**$20,386**	**$187**	**$5,833**	**$408**		**$26,814**	**$2,145**		**$2,442**	**$31,401**	**82**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	3,304		748	52		$4,104	328		665	$5,097	13
9.2	Circulating Water Pumps	483		47	3		$534	43		58	$634	2
9.3	Circ.Water System Auxiliaries	59		9	1		$68	5		15	$88	0
9.4	Circ.Water Piping		1,146	1,314	92		$2,552	204		689	$3,445	9
9.5	Make-up Water System	132		201	14		$346	28		94	$468	1
9.6	Component Cooling Water Sys	127		115	8		$250	20		54	$324	1
9.9	Circ.Water System Foundations		850	1,526	107		$2,483	199		670	$3,352	9
	SUBTOTAL 9.	**$4,104**	**$1,996**	**$3,960**	**$277**		**$10,337**	**$827**		**$2,244**	**$13,409**	**35**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Gasifier Ash Removal	2,499		1,367	96		$3,962	475	594	755	$5,786	15
10.2	Gasifier Ash Depressurization	1,026	50	239	17		$1,331	106		216	$1,653	4
10.3	Cleanup Ash Depressurization	2,451	302	553	39		$3,344	268		542	$4,153	11
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	463		519	36		$1,018	81		165	$1,265	3
10.7	Ash Transport & Feed Equipment	603		154	11		$768	61		207	$1,037	3
10.8	Misc. Ash Handling Equipment	959	1,175	362	25		$2,520	202		544	$3,266	8
10.9	Ash/Spent Sorbent Foundation		40	53	4		$97	8		26	$131	0
	SUBTOTAL 10.	**$8,000**	**$1,567**	**$3,246**	**$227**		**$13,040**	**$1,202**	**$594**	**$2,455**	**$17,291**	**45**

	Client:	DEPARTMENT OF ENERGY							**Report Date:**		23-Jul-99	
	Project:	TASK 9-3 CCT Evaluation Guide									01:08 PM	

TOTAL PLANT COST SUMMARY

Case: IGCC - KRW x 3

Plant Size: 384.9 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,767		284	20		$2,070	166		224	$2,460	6
11.2	Station Service Equipment	2,289		191	13		$2,494	199		269	$2,962	8
11.3	Switchgear & Motor Control	1,825		307	21		$2,154	172		349	$2,675	7
11.4	Conduit & Cable Tray		1,101	3,492	244		$4,837	387		1,045	$6,269	16
11.5	Wire & Cable		1,181	1,193	84		$2,458	197		531	$3,186	8
11.6	Protective Equipment		100	337	24		$461	37		50	$547	1
11.7	Standby Equipment	260		6	0		$266	21		29	$316	1
11.8	Main Power Transformers	4,168		473	33		$4,673	374		505	$5,552	14
11.9	Electrical Foundations		161	450	31		$642	51		173	$867	2
	SUBTOTAL 11.	**$10,309**	**$2,543**	**$6,732**	**$471**		**$20,055**	**$1,604**		**$3,174**	**$24,833**	**65**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	492		304	21		$817	65		132	$1,015	3
12.5	Signal Processing Equipment	w/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	118		70	5		$193	15		31	$240	1
12.7	Computer & Accessories	4,707		139	10		$4,856	388		524	$5,769	15
12.8	Instrument Wiring & Tubing		1,469	4,615	323		$6,407	513		1,384	$8,304	22
12.9	Other I & C Equipment	866		389	27		$1,283	103		346	$1,732	4
	SUBTOTAL 12.	**$6,183**	**$1,469**	**$5,518**	**$386**		**$13,556**	**$1,084**		**$2,418**	**$17,059**	**44**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		32	633	44		$709	57		230	$995	3
13.2	Site Improvements		1,045	1,305	91		$2,441	195		791	$3,427	9
13.3	Site Facilities	1,872		1,856	130		$3,858	309		1,250	$5,417	14
	SUBTOTAL 13.	**$1,872**	**$1,076**	**$3,794**	**$266**		**$7,008**	**$561**		**$2,270**	**$9,839**	**26**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		218	139	10		$367	29		79	$476	1
14.2	Steam Turbine Building		2,013	3,231	226		$5,470	438		1,182	$7,090	18
14.3	Administration Building		429	351	25		$804	64		174	$1,042	3
14.4	Circulation Water Pumphouse		85	50	4		$139	11		30	$180	0
14.5	Water Treatment Buildings		535	588	41		$1,164	93		252	$1,509	4
14.6	Machine Shop		220	169	12		$401	32		87	$519	1
14.7	Warehouse		355	258	18		$630	50		136	$817	2
14.8	Other Buildings & Structures		212	186	13		$412	33		89	$534	1
14.9	Waste Treating Building & Str.		475	1,022	72		$1,568	125		339	$2,033	5
	SUBTOTAL 14.		**$4,541**	**$5,996**	**$420**		**$10,956**	**$876**		**$2,367**	**$14,199**	**37**
	TOTAL COST	**$239,906**	**$32,604**	**$107,250**	**$7,508**		**$387,268**	**$37,541**	**$34,630**	**$80,086**	**$539,525**	**1402**

OPERATING LABOR REQUIREMENTS

IGCC - KRW x 3

Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:

Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	9.0	9.0
Foreman	1.0	1.0
Lab Tech's, etc.	3.0	3.0
TOTAL-O.J.'s	15.0	15.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA

IGCC - KRW x 3

Item/Description	Consumption Initial	Consumption /Day	Unit Cost
Water(/1000 gallons)		3,283	0.80
Chemicals*			
MU & WT Chem.(lbs)**	238,377	7,946	0.15
Limestone (ton)**	18,582	619.4	16.25
Z Sorb (lbs)**	21,600	720.0	3.50
Nahcolite(ton)**	86	2.9	275.00
Other			
Supplemental Fuel(MBtu)**			
Gases,N2 etc.(/100scf)			
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		848	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		2,869	29.63

CONTINGENCY FACTORS

IGCC - KRW x 3

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		21.5
COAL & SORBENT PREP & FEED	3.0	17.9
FEEDWATER & MISC. BOP SYSTEMS		21.0
GASIFIER & ACCESSORIES		
Gasifier & Auxiliaries	15.0	15.0
High Temperature Cooling	15.0	15.0
Recycle Gas System	15.0	15.0
Other Gasification Equipment	8.9	18.0
HOT GAS CLEANUP & PIPING	18.9	25.6
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	15.0	10.0
Combustion Turbine Accessories		30.0
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		5.0
HRSG Accessories, Ductwork and Stack		16.9
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		14.2
COOLING WATER SYSTEM		20.1
ASH/SPENT SORBENT HANDLING SYS	4.6	16.5
ACCESSORY ELECTRIC PLANT		14.7
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS

IGCC - KRW x 3

Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.2
COAL & SORBENT PREP & FEED	3.0
FEEDWATER & MISC. BOP SYSTEMS	1.9
GASIFIER & ACCESSORIES	
Gasifier & Auxiliaries	5.0
High Temperature Cooling	4.5
Recycle Gas System	4.0
Other Gasification Equipment	3.0
HOT GAS CLEANUP & PIPING	5.3
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	6.0
Combustion Turbine Accessories	0.5
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.5
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.2
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.2
BUILDINGS & STRUCTURES	1.4

IGCC - KRW Air-Blown 200 MWe

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC - KRW x2		
Plant Size:	198.1 (MW,net)	HeatRate:	8,086 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	3 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		250,804	1266.1
Engineering(incl.C.M.,H.O.& Fee)		24,208	122.2
Process Contingency		21,076	106.4
Project Contingency		52,034	262.7
TOTAL PLANT COST(TPC)		$348,123	1757.4
TOTAL CASH EXPENDED	$348,123		
AFDC	$29,472		
TOTAL PLANT INVESTMENT(TPI)		$377,595	1906.2
Royalty Allowance			
Preproduction Costs		9,228	46.6
Inventory Capital		2,388	12.1
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		338	1.7
TOTAL CAPITAL REQUIREMENT(TCR)		$389,548	1966.6

OPERATING & MAINTENANCE COSTS (1999 Dollars)	$x1000	$/kW-yr
Operating Labor	3,871	19.5
Maintenance Labor	2,100	10.6
Maintenance Material	3,151	15.9
Administrative & Support Labor	1,493	7.5
TOTAL OPERATION & MAINTENANCE	$10,616	53.6
FIXED O & M		45.55 $/kW-yr
VARIABLE O & M		0.11 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	$x1000	¢/kWh
Water	408	0.03
Chemicals	2,661	0.18
Other Consumables		
Waste Disposal	1,511	0.10
TOTAL CONSUMABLE OPERATING COSTS	$4,579	0.31
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$15,146	1.03

	1st Year (2005 $)		Levelized (10th.Year $)	
PRODUCTION COST SUMMARY		¢/kWh		¢/kWh
Fixed O & M	45.6/kW-yr	0.61	45.6/kW-yr	0.61
Variable O & M		0.11		0.11
Consumables		0.31		0.31
By-product Credit				
Fuel		0.95		0.89
TOTAL PRODUCTION COST		1.98		1.92
LEVELIZED CARRYING CHARGES(Capital)			297.0/kW-yr	3.99
LEVELIZED (10th.Year) BUSBAR COST OF POWER				5.90

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC - KRW x2			
Unit Size:/Plant Size:	198.1	MW,net	198.1	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	8,086	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	3	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	225	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		01:06 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC - KRW x2					
Plant Size:	198.1 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	1,722		967	68		$2,756	221		595	$3,572	18
1.2	Coal Stackout & Reclaim	2,225		620	43		$2,888	231		624	$3,743	19
1.3	Coal Conveyors & Yd Crush	2,069		613	43		$2,725	218		589	$3,532	18
1.4	Other Coal Handling	541		142	10		$693	55		150	$898	5
1.5	Sorbent Receive & Unload	47		17	1		$65	5		14	$84	0
1.6	Sorbent Stackout,Storage & Reclaim	1,470		494	35		$1,998	160		432	$2,590	13
1.7	Sorbent Conveyors	886	78	237	17		$1,217	97		263	$1,577	8
1.8	Other Sorbent Handling	231	51	149	10		$441	35		95	$572	3
1.9	Coal & Sorbent Hnd.Foundations		2,093	2,981	209		$5,282	423		1,426	$7,131	36
	SUBTOTAL 1.	**$9,192**	**$2,221**	**$6,219**	**$435**		**$18,067**	**$1,445**		**$4,188**	**$23,700**	**120**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	520	81	199	14		$814	65		176	$1,055	5
2.2	Prepared Coal Storage & Feed	179	40	32	2		$254	20		55	$329	2
2.3	Coal & Sorbent Feed System	3,480		1,903	133		$5,516	662	276	968	$7,421	37
2.4	Misc.Coal Prep & Feed	253	173	635	44		$1,105	88		298	$1,492	8
2.5	Sorbent Prep Equipment	571	50	235	16		$872	70		188	$1,130	6
2.6	Sorbent Storage & Feed	150		35	2		$188	15		41	$244	1
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		536	464	32		$1,033	83		279	$1,394	7
	SUBTOTAL 2.	**$5,153**	**$880**	**$3,503**	**$245**		**$9,781**	**$1,003**	**$276**	**$2,005**	**$13,065**	**66**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	553	2,152	585	41		$3,331	266		540	$4,137	21
3.2	Water Makeup & Pretreating	225	24	132	9		$389	31		84	$505	3
3.3	Other Feedwater Subsystems	329	123	114	8		$574	46		124	$744	4
3.4	Service Water Systems	17	37	133	9		$197	16		42	$255	1
3.5	Other Boiler Plant Systems	735	297	758	53		$1,843	147		498	$2,488	13
3.6	FO Supply Sys & Nat Gas	64	121	232	16		$434	35		94	$562	3
3.7	Waste Treatment Equipment	448		267	19		$734	59		159	$951	5
3.8	Misc. Power Plant Equipment	1,230	166	623	44		$2,064	165		669	$2,897	15
	SUBTOTAL 3.	**$3,602**	**$2,920**	**$2,845**	**$199**		**$9,566**	**$765**		**$2,209**	**$12,540**	**63**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries	20,343		11,121	778		$32,242	3,869	4,836	6,142	$47,090	238
4.2	High Temperature Cooling	3,458		1,890	132		$5,481	658	822	1,044	$8,005	40
4.3	Recycle Gas System	2,176		1,190	83		$3,449	414	517	657	$5,037	25
4.4	Booster Air Compression	7,160		1,817	127		$9,104	1,092	1,366	1,734	$13,296	67
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment		627	263	18		$909	73		147	$1,129	6
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations		2,342	1,410	99		$3,850	308		1,040	$5,198	26
	SUBTOTAL 4.	**$33,137**	**$2,969**	**$17,691**	**$1,238**		**$55,035**	**$6,414**	**$7,541**	**$10,764**	**$79,755**	**403**

Client: DEPARTMENT OF ENERGY | Report Date: 23-Jul-99 01:06 PM
Project: TASK 9-3 CCT Evaluation Guide

TOTAL PLANT COST SUMMARY

Case: IGCC - KRW x2
Plant Size: 198.1 MW,net | Estimate Type: Conceptual | Cost Base (Jan) 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Gas Desulfurization(Trans.Reactor)	5,793		3,167	222		$9,182	1,102	1,377	3,498	$15,159	77
5.2	Sulfur Recovery (Sulfator Sys.)	11,088		6,063	424		$17,575	2,109	2,636	6,696	$29,017	146
5.3	Chloride Guard	4,671		1,131	79		$5,880	706	1,470	2,014	$10,070	51
5.4	Particulate Removal	8,171		1,027	72		$9,270	1,112	2,318	2,540	$15,240	77
5.5	Blowback Gas Systems	1,678	1,091	633	44		$3,447	414	862	945	$5,667	29
5.6	Fuel Gas Piping		1,207	935	65		$2,206	177		596	$2,979	15
5.9	HGCU Foundations		218	148	10		$376	30		102	$508	3
	SUBTOTAL 5.	**$31,401**	**$2,516**	**$13,103**	**$917**		**$47,937**	**$5,649**	**$8,663**	**$16,390**	**$78,639**	**397**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	26,766		1,330	93		$28,189	2,255	4,228	3,467	$38,140	193
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		97	113	8		$218	17		71	$306	2
	SUBTOTAL 6.	**$26,766**	**$97**	**$1,443**	**$101**		**$28,407**	**$2,273**	**$4,228**	**$3,538**	**$38,445**	**194**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	9,254		2,013	141		$11,408	913		616	$12,937	65
7.2	HRSG Accessories											
7.3	Ductwork											
7.4	Stack	298		499	35		$832	67		135	$1,033	5
7.9	HRSG,Duct & Stack Foundations		70	87	6		$163	13		44	$220	1
	SUBTOTAL 7.	**$9,552**	**$70**	**$2,599**	**$182**		**$12,403**	**$992**		**$795**	**$14,190**	**72**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	8,599		1,446	101		$10,146	812		548	$11,505	58
8.2	Turbine Plant Auxiliaries	61		145	10		$216	17		35	$268	1
8.3	Condenser & Auxiliaries	1,576		445	31		$2,053	164		222	$2,438	12
8.4	Steam Piping	2,238		1,203	84		$3,525	282		571	$4,378	22
8.9	TG Foundations		118	376	26		$520	42		141	$703	4
	SUBTOTAL 8.	**$12,474**	**$118**	**$3,615**	**$253**		**$16,460**	**$1,317**		**$1,516**	**$19,293**	**97**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	2,124		481	34		$2,639	211		428	$3,278	17
9.2	Circulating Water Pumps	311		30	2		$343	27		37	$408	2
9.3	Circ.Water System Auxiliaries	38		6	0		$44	4		9	$57	0
9.4	Circ.Water Piping		737	845	59		$1,641	131		443	$2,215	11
9.5	Make-up Water System	85		129	9		$223	18		60	$301	2
9.6	Component Cooling Water Sys	82		74	5		$161	13		35	$209	1
9.9	Circ.Water System Foundations		547	981	69		$1,597	128		431	$2,155	11
	SUBTOTAL 9.	**$2,639**	**$1,283**	**$2,546**	**$178**		**$6,647**	**$532**		**$1,443**	**$8,622**	**44**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Gasifier Ash Removal	1,546		845	59		$2,451	294	368	467	$3,579	18
10.2	Gasifier Ash Depressurization	634	31	148	10		$823	66		133	$1,023	5
10.3	Cleanup Ash Depressurization	1,516	187	342	24		$2,069	165		335	$2,569	13
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	340		382	27		$749	60		121	$930	5
10.7	Ash Transport & Feed Equipment	443		114	8		$565	45		153	$763	4
10.8	Misc. Ash Handling Equipment	705	864	266	19		$1,853	148		400	$2,402	12
10.9	Ash/Spent Sorbent Foundation		29	39	3		$71	6		19	$96	0
	SUBTOTAL 10.	**$5,185**	**$1,111**	**$2,135**	**$149**		**$8,580**	**$784**	**$368**	**$1,629**	**$11,361**	**57**

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		01:06 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC - KRW x2						
Plant Size:	198.1 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,182		190	13		$1,385	111		150	$1,646	8
11.2	Station Service Equipment	1,741		145	10		$1,897	152		205	$2,253	11
11.3	Switchgear & Motor Control	1,388		234	16		$1,638	131		265	$2,034	10
11.4	Conduit & Cable Tray		837	2,656	186		$3,679	294		795	$4,768	24
11.5	Wire & Cable		899	907	64		$1,870	150		404	$2,423	12
11.6	Protective Equipment		62	208	15		$285	23		31	$338	2
11.7	Standby Equipment	161		4	0		$164	13		18	$195	1
11.8	Main Power Transformers	2,577		292	20		$2,890	231		312	$3,433	17
11.9	Electrical Foundations		99	278	19		$397	32		107	$536	3
	SUBTOTAL 11.	**$7,049**	**$1,897**	**$4,914**	**$344**		**$14,205**	**$1,136**		**$2,286**	**$17,627**	**89**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	383		237	17		$637	51		103	$791	4
12.5	Signal Processing Equipment	w/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	92		55	4		$150	12		24	$187	1
12.7	Computer & Accessories	3,666		109	8		$3,782	303		408	$4,493	23
12.8	Instrument Wiring & Tubing		1,144	3,595	252		$4,991	399		1,078	$6,468	33
12.9	Other I & C Equipment	675		303	21		$999	80		270	$1,349	7
	SUBTOTAL 12.	**$4,816**	**$1,144**	**$4,298**	**$301**		**$10,559**	**$845**		**$1,884**	**$13,287**	**67**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		23	457	32		$511	41		166	$718	4
13.2	Site Improvements		754	942	66		$1,761	141		571	$2,473	12
13.3	Site Facilities	1,351		1,340	94		$2,784	223		902	$3,909	20
	SUBTOTAL 13.	**$1,351**	**$777**	**$2,738**	**$192**		**$5,057**	**$405**		**$1,639**	**$7,100**	**36**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		163	104	7		$274	22		59	$355	2
14.2	Steam Turbine Building		1,379	2,213	155		$3,746	300		809	$4,855	25
14.3	Administration Building		342	280	20		$641	51		138	$831	4
14.4	Circulation Water Pumphouse		67	40	3		$110	9		24	$143	1
14.5	Water Treatment Buildings		427	469	33		$928	74		201	$1,203	6
14.6	Machine Shop		175	135	9		$320	26		69	$414	2
14.7	Warehouse		283	206	14		$503	40		109	$651	3
14.8	Other Buildings & Structures		169	149	10		$328	26		71	$425	2
14.9	Waste Treating Building & Str.		378	815	57		$1,250	100		270	$1,621	8
	SUBTOTAL 14.		**$3,383**	**$4,410**	**$309**		**$8,101**	**$648**		**$1,750**	**$10,499**	**53**
	TOTAL COST	**$152,317**	**$21,385**	**$72,058**	**$5,044**		**$250,804**	**$24,208**	**$21,076**	**$52,034**	**$348,123**	**1757**

OPERATING LABOR REQUIREMENTS

IGCC - KRW x2

Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:

Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	8.0	8.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	13.0	13.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA

IGCC - KRW x2

Item/Description	Consumption Initial	Consumption /Day	Unit Cost
Water(/1000 gallons)		1,642	0.80
Chemicals*			
MU & WT Chem.(lbs)**	119,225	3,974	0.15
Limestone (ton)**	10,687	356.2	16.25
Z Sorb (lbs)**	14,400	480.0	3.50
Nahcolite(ton)**	58	1.9	275.00
Other			
Supplemental Fuel(MBtu)**			
Gases,N2 etc.(/100scf)			
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		487	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		1,648	29.63

CONTINGENCY FACTORS

IGCC - KRW x2

Item/Description	Contingency Factors(%) %Process	Contingency Factors(%) %Project
COAL & SORBENT HANDLING		21.5
COAL & SORBENT PREP & FEED	2.8	18.1
FEEDWATER & MISC. BOP SYSTEMS		21.4
GASIFIER & ACCESSORIES		
Gasifier & Auxiliaries	15.0	15.0
High Temperature Cooling	15.0	15.0
Recycle Gas System	15.0	15.0
Other Gasification Equipment	9.9	17.5
HOT GAS CLEANUP & PIPING	18.1	26.3
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	15.0	10.0
Combustion Turbine Accessories		30.0
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		5.0
HRSG Accessories, Ductwork and Stack		16.6
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		14.2
COOLING WATER SYSTEM		20.1
ASH/SPENT SORBENT HANDLING SYS	4.3	16.7
ACCESSORY ELECTRIC PLANT		14.9
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS

IGCC - KRW x2

Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.2
COAL & SORBENT PREP & FEED	3.0
FEEDWATER & MISC. BOP SYSTEMS	1.9
GASIFIER & ACCESSORIES	
Gasifier & Auxiliaries	5.0
High Temperature Cooling	4.5
Recycle Gas System	4.0
Other Gasification Equipment	3.2
HOT GAS CLEANUP & PIPING	4.9
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	6.0
Combustion Turbine Accessories	0.5
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.3
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.2
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.2
BUILDINGS & STRUCTURES	1.4

IGCC - Oxygen-Blown Destec 380 MWe

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	IGCC - Destec		
Plant Size:	348.2 (MW,net)	HeatRate:	7,526 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		357,724	1027.3
Engineering(incl.C.M.,H.O.& Fee)		32,600	93.6
Process Contingency		17,380	49.9
Project Contingency		58,889	169.1
TOTAL PLANT COST(TPC)		$466,594	1339.9
TOTAL CASH EXPENDED	$466,594		
AFDC	$29,918		
TOTAL PLANT INVESTMENT(TPI)		$496,512	1425.8
Royalty Allowance			
Preproduction Costs		11,954	34.3
Inventory Capital		3,526	10.1
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.3
TOTAL CAPITAL REQUIREMENT(TCR)		$512,442	1471.6

OPERATING & MAINTENANCE COSTS (1999 Dollars)	$x1000	$/kW-yr
Operating Labor	4,765	13.7
Maintenance Labor	2,878	8.3
Maintenance Material	4,317	12.4
Administrative & Support Labor	1,911	5.5
TOTAL OPERATION & MAINTENANCE	$13,870	39.8
FIXED O & M		33.86 $/kW-yr
VARIABLE O & M		0.08 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	$x1000	¢/kWh
Water	702	0.03
Chemicals	1,601	0.06
Other Consumables		
Waste Disposal	834	0.03
TOTAL CONSUMABLE OPERATING COSTS	$3,136	0.12
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$24,783	0.96

	1st Year (2005 $)		Levelized (10th.Year $)	
PRODUCTION COST SUMMARY		¢/kWh		¢/kWh
Fixed O & M	33.9/kW-yr	0.45	33.9/kW-yr	0.45
Variable O & M		0.08		0.08
Consumables		0.12		0.12
By-product Credit				
Fuel		0.88		0.82
TOTAL PRODUCTION COST		1.54		1.48
LEVELIZED CARRYING CHARGES(Capital)			222.2/kW-yr	2.98
LEVELIZED (10th.Year) BUSBAR COST OF POWER				4.46

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	IGCC - Destec			
Unit Size:/Plant Size:	348.2	MW,net	348.2	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	7,526	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

Client:	DEPARTMENT OF ENERGY							**Report Date:**	23-Jul-99	
									01:04 PM	
Project:	TASK 9-3 CCT Evaluation Guide									
Case:	IGCC - Destec									
Plant Size:	348.2 MW,net		**Estimate Type:**	Conceptual			**Cost Base (Jan)**	1999	($x1000)	

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,337		1,312	92		$3,740	299		808	$4,847	14
1.2	Coal Stackout & Reclaim	3,020		841	59		$3,920	314		847	$5,080	15
1.3	Coal Conveyors & Yd Crush	2,808		832	58		$3,698	296		799	$4,792	14
1.4	Other Coal Handling	735		193	13		$941	75		203	$1,219	4
1.5	Sorbent Receive & Unload											
1.6	Sorbent Stackout & Reclaim											
1.7	Sorbent Conveyors											
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations		1,800	4,749	332		$6,881	551		1,858	$9,290	27
	SUBTOTAL 1.	**$8,899**	**$1,800**	**$7,926**	**$555**		**$19,180**	**$1,534**		**$4,514**	**$25,228**	**72**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	894	139	342	24		$1,399	112		302	$1,813	5
2.2	Prepared Coal Storage & Feed	307	69	55	4		$436	35		94	$564	2
2.3	Slurry Prep & Feed	4,984		5,091	356		$10,431	1,252	522	1,831	$14,035	40
2.4	Misc.Coal Prep & Feed	435	297	1,091	76		$1,899	152		513	$2,563	7
2.5	Sorbent Prep Equipment											
2.6	Sorbent Storage & Feed											
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation		1,841	1,595	112		$3,548	284		958	$4,790	14
	SUBTOTAL 2.	**$6,620**	**$2,346**	**$8,174**	**$572**		**$17,713**	**$1,834**	**$522**	**$3,698**	**$23,766**	**68**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	796	3,094	842	59		$4,791	383		776	$5,950	17
3.2	Water Makeup & Pretreating	336	36	197	14		$582	47		126	$754	2
3.3	Other Feedwater Subsystems	473	177	164	11		$826	66		178	$1,070	3
3.4	Service Water Systems	26	55	198	14		$294	23		63	$381	1
3.5	Other Boiler Plant Systems	1,098	443	1,133	79		$2,754	220		744	$3,718	11
3.6	FO Supply Sys & Nat Gas	94	178	341	24		$637	51		138	$826	2
3.7	Waste Treatment Equipment	670		399	28		$1,097	88		237	$1,421	4
3.8	Misc. Power Plant Equipment	1,807	244	915	64		$3,031	242		982	$4,255	12
	SUBTOTAL 3.	**$5,300**	**$4,228**	**$4,190**	**$293**		**$14,011**	**$1,121**		**$3,244**	**$18,375**	**53**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)	8,591		8,895	623		$18,108	2,173	1,811	3,314	$25,406	73
4.2	High Temperature Cooling	14,113		14,618	1,023		$29,755	3,571	2,975	5,445	$41,746	120
4.3	ASU/Oxidant Compression	45,454		w/equip.			$45,454	3,636		4,909	$53,999	155
4.4	Booster Air Compression											
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment		664	279	20		$963	116		162	$1,240	4
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations		2,995	1,803	126		$4,925	394		1,330	$6,649	19
	SUBTOTAL 4.	**$68,158**	**$3,660**	**$25,595**	**$1,792**		**$99,204**	**$9,889**	**$4,786**	**$15,159**	**$129,039**	**371**

Client:	DEPARTMENT OF ENERGY		**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide			01:04 PM

TOTAL PLANT COST SUMMARY

Case:	IGCC - Destec					
Plant Size:	348.2 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Gas Desulfurization(GE Moving Bed)	6,386		2,099	147		$8,633	1,036	2,158	2,957	$14,783	42
5.2	Sulfur Recovery (Sulfuric Acid)	12,342		3,983	279		$16,604	1,993	1,660	4,051	$24,309	70
5.3	Chloride Guard	2,905		703	49		$3,658	439	914	1,253	$6,264	18
5.4	Particulate Removal	4,175		525	37		$4,736	568	1,184	1,298	$7,786	22
5.5	Blowback Gas Systems	1,078	350	203	14		$1,645	197	411	451	$2,705	8
5.6	Fuel Gas Piping		772	598	42		$1,413	113		381	$1,907	5
5.9	HGCU Foundations		820	558	39		$1,417	113		383	$1,913	5
	SUBTOTAL 5.	**$26,886**	**$1,943**	**$8,670**	**$607**		**$38,105**	**$4,459**	**$6,328**	**$10,773**	**$59,666**	**171**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	49,250		2,956	207		$52,413	4,193	5,241	3,092	$64,940	186
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		143	167	12		$321	26		104	$450	1
	SUBTOTAL 6.	**$49,250**	**$143**	**$3,123**	**$219**		**$52,734**	**$4,219**	**$5,241**	**$3,196**	**$65,390**	**188**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	14,150		2,074	145		$16,369	1,310		884	$18,563	53
7.2	HRSG Accessories											
7.3	Ductwork		613	537	38		$1,188	95		257	$1,540	4
7.4	Stack	1,899		735	51		$2,686	215		435	$3,336	10
7.9	HRSG,Duct & Stack Foundations		94	95	7		$196	16		53	$265	1
	SUBTOTAL 7.	**$16,049**	**$707**	**$3,442**	**$241**		**$20,439**	**$1,635**		**$1,629**	**$23,702**	**68**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	12,134		2,040	143		$14,317	1,145		773	$16,236	47
8.2	Turbine Plant Auxiliaries	84		198	14		$295	24		48	$367	1
8.3	Condenser & Auxiliaries	2,155		609	43		$2,806	225		303	$3,334	10
8.4	Steam Piping	3,060		1,645	115		$4,820	386		781	$5,986	17
8.9	TG Foundations		161	514	36		$712	57		192	$961	3
	SUBTOTAL 8.	**$17,433**	**$161**	**$5,006**	**$350**		**$22,951**	**$1,836**		**$2,097**	**$26,884**	**77**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	2,868		649	45		$3,562	285		577	$4,424	13
9.2	Circulating Water Pumps	419		41	3		$463	37		50	$550	2
9.3	Circ.Water System Auxiliaries	51		8	1		$59	5		13	$77	0
9.4	Circ.Water Piping		994	1,141	80		$2,215	177		598	$2,990	9
9.5	Make-up Water System	114		174	12		$301	24		81	$406	1
9.6	Component Cooling Water Sys	110		100	7		$217	17		47	$282	1
9.9	Circ.Water System Foundations		738	1,324	93		$2,155	172		582	$2,909	8
	SUBTOTAL 9.	**$3,562**	**$1,733**	**$3,437**	**$241**		**$8,973**	**$718**		**$1,948**	**$11,638**	**33**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling	2,409		2,449	171		$5,029	603	503	920	$7,056	20
10.2	Gasifier Ash Depressurization											
10.3	Cleanup Ash Depressurization											
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	246		276	19		$542	43		88	$673	2
10.7	Ash Transport & Feed Equipment	321		82	6		$409	33		110	$552	2
10.8	Misc. Ash Handling Equipment	510	625	192	13		$1,341	107		290	$1,738	5
10.9	Ash/Spent Sorbent Foundation		21	28	2		$51	4		14	$69	0
	SUBTOTAL 10.	**$3,486**	**$646**	**$3,028**	**$212**		**$7,372**	**$791**	**$503**	**$1,422**	**$10,088**	**29**

Client: DEPARTMENT OF ENERGY **Report Date:** 23-Jul-99 01:04 PM

Project: TASK 9-3 CCT Evaluation Guide

TOTAL PLANT COST SUMMARY

Case: IGCC - Destec

Plant Size: 348.2 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,731		278	19		$2,028	162		219	$2,410	7
11.2	Station Service Equipment	3,571		298	21		$3,890	311		420	$4,621	13
11.3	Switchgear & Motor Control	2,847		479	34		$3,360	269		544	$4,173	12
11.4	Conduit & Cable Tray		1,717	5,447	381		$7,546	604		1,630	$9,779	28
11.5	Wire & Cable		1,843	1,861	130		$3,834	307		828	$4,969	14
11.6	Protective Equipment		98	329	23		$449	36		49	$534	2
11.7	Standby Equipment	253		6	0		$259	21		28	$308	1
11.8	Main Power Transformers	4,067		461	32		$4,560	365		493	$5,418	16
11.9	Electrical Foundations		157	439	31		$626	50		169	$846	2
	SUBTOTAL 11.	**$12,469**	**$3,815**	**$9,598**	**$672**		**$26,553**	**$2,124**		**$4,380**	**$33,057**	**95**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	483		299	21		$803	64		130	$997	3
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	116		69	5		$190	15		31	$235	1
12.7	Computer & Accessories	4,625		137	10		$4,771	382		515	$5,668	16
12.8	Instrument Wiring & Tubing		1,443	4,535	317		$6,296	504		1,360	$8,159	23
12.9	Other I & C Equipment	851		382	27		$1,260	101		340	$1,702	5
	SUBTOTAL 12.	**$6,075**	**$1,443**	**$5,422**	**$380**		**$13,320**	**$1,066**		**$2,376**	**$16,762**	**48**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		31	622	44		$697	56		226	$978	3
13.2	Site Improvements		1,027	1,283	90		$2,400	192		778	$3,370	10
13.3	Site Facilities	1,841		1,826	128		$3,795	304		1,229	$5,328	15
	SUBTOTAL 13.	**$1,841**	**$1,058**	**$3,731**	**$261**		**$6,892**	**$551**		**$2,233**	**$9,676**	**28**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		224	143	10		$377	30		81	$489	1
14.2	Steam Turbine Building		1,781	2,860	200		$4,841	387		1,046	$6,274	18
14.3	Administration Building		424	347	24		$795	64		172	$1,030	3
14.4	Circulation Water Pumphouse		84	50	3		$137	11		30	$177	1
14.5	Water Treatment Buildings		529	581	41		$1,151	92		249	$1,492	4
14.6	Machine Shop		217	167	12		$396	32		86	$513	1
14.7	Warehouse		350	255	18		$623	50		135	$808	2
14.8	Other Buildings & Structures		210	184	13		$407	33		88	$527	2
14.9	Waste Treating Building & Str.		469	1,010	71		$1,550	124		335	$2,009	6
	SUBTOTAL 14.		**$4,289**	**$5,598**	**$392**		**$10,278**	**$822**		**$2,220**	**$13,320**	**38**
	TOTAL COST	**$226,028**	**$27,971**	**$96,939**	**$6,786**		**$357,724**	**$32,600**	**$17,380**	**$58,889**	**$466,594**	**1340**

OPERATING LABOR REQUIREMENTS

IGCC - Destec

Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:

Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	10.0	10.0
Foreman	1.0	1.0
Lab Tech's, etc.	3.0	3.0
TOTAL-O.J.'s	16.0	16.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA

IGCC - Destec

Item/Description	Consumption Initial	Consumption /Day	Unit Cost
Water(/1000 gallons)		2,827	0.80
Chemicals			
MU & WT Chem.(lbs)	205,267	6,842	0.15
Limestone (ton)			16.25
Z Sorb (ton)**	15	0.5	7000.00
Nahcolite(ton)	72	2.4	275.00
Other			
Supplemental Fuel(MBtu)			
Gases,N2 etc.(/100scf)			1.50
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		269	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		2,696	29.63

CONTINGENCY FACTORS

IGCC - Destec

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		21.8
COAL & SORBENT PREP & FEED	2.9	18.4
FEEDWATER & MISC. BOP SYSTEMS		21.4
GASIFIER & ACCESSORIES		
Gasifier & Auxiliaries(Destec)	10.0	15.0
High Temperature Cooling	10.0	15.0
ASU/Oxidant Compression		10.0
Other Gasification Equipment		23.3
HOT GAS CLEANUP & PIPING	16.6	22.0
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	10.0	5.0
Combustion Turbine Accessories		30.0
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		5.0
HRSG Accessories, Ductwork and Stack		16.9
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		14.2
COOLING WATER SYSTEM		20.1
ASH/SPENT SORBENT HANDLING SYS	6.8	16.4
ACCESSORY ELECTRIC PLANT		15.3
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS IGCC - Destec	
Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.0
COAL & SORBENT PREP & FEED	2.7
FEEDWATER & MISC. BOP SYSTEMS	1.9
GASIFIER & ACCESSORIES	
Gasifier & Auxiliaries(Destec)	5.0
High Temperature Cooling	4.5
ASU/Oxidant Compression	4.0
Other Gasification Equipment	0.7
HOT GAS CLEANUP & PIPING	4.4
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	6.0
Combustion Turbine Accessories	0.5
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.5
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.0
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.2
BUILDINGS & STRUCTURES	1.4

CPFBC - Maximum Power

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	2gPFBCw/Boost-Max.Power		
Plant Size:	431.3 (MW,net)	HeatRate:	7,463 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		347,923	806.7
Engineering(incl.C.M.,H.O.& Fee)		30,363	70.4
Process Contingency		21,733	50.4
Project Contingency		58,401	135.4
TOTAL PLANT COST(TPC)		$458,419	1062.9
TOTAL CASH EXPENDED	$458,419		
AFDC	$29,394		
TOTAL PLANT INVESTMENT(TPI)		$487,813	1131.0
Royalty Allowance			
Preproduction Costs		12,172	28.2
Inventory Capital		4,122	9.6
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.0
TOTAL CAPITAL REQUIREMENT(TCR)		$504,556	1169.9

OPERATING & MAINTENANCE COSTS (1999 Dollars)	$x1000	$/kW-yr
Operating Labor	3,871	9.0
Maintenance Labor	2,886	6.7
Maintenance Material	4,330	10.0
Administrative & Support Labor	1,689	3.9
TOTAL OPERATION & MAINTENANCE	$12,777	29.6
FIXED O & M		25.18 $/kW-yr
VARIABLE O & M		0.06 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	$x1000	¢/kWh
Water	953	0.03
Chemicals	3,126	0.10
Other Consumables		
Waste Disposal	2,679	0.08
TOTAL CONSUMABLE OPERATING COSTS	$6,757	0.21
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$30,438	0.95

	1st Year (2005 $)		Levelized (10th.Year $)	
PRODUCTION COST SUMMARY		¢/kWh		¢/kWh
Fixed O & M	25.2/kW-yr	0.34	25.2/kW-yr	0.34
Variable O & M		0.06		0.06
Consumables		0.21		0.21
By-product Credit				
Fuel		0.87		0.82
TOTAL PRODUCTION COST		1.48		1.43
LEVELIZED CARRYING CHARGES(Capital)			176.6/kW-yr	2.37
LEVELIZED (10th.Year) BUSBAR COST OF POWER				3.80

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	2gPFBCw/Boost-Max.Power			
Unit Size:/Plant Size:	431.3	MW,net	431.3	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	7,463	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

Client: DEPARTMENT OF ENERGY **Report Date:** 23-Jul-99 12:56 PM
Project: TASK 9-3 CCT Evaluation Guide

TOTAL PLANT COST SUMMARY

Case: 2gPFBCw/Boost-Max.Power
Plant Size: 431.3 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,655		1,490	104		$4,249	340		918	$5,506	13
1.2	Coal Stackout & Reclaim	3,430		955	67		$4,452	356		962	$5,770	13
1.3	Coal Conveyors & Yd Crush	3,189		945	66		$4,201	336		907	$5,444	13
1.4	Other Coal Handling	834		219	15		$1,068	85		231	$1,385	3
1.5	Sorbent Receive & Unload	60		22	2		$84	7		18	$109	0
1.6	Sorbent Stackout & Reclaim	1,910		642	45		$2,597	208		561	$3,366	8
1.7	Sorbent Conveyors	1,152	101	308	22		$1,582	127		342	$2,050	5
1.8	Other Sorbent Handling	301	66	194	14		$574	46		155	$775	2
1.9	Coal & Sorbent Hnd.Foundations	191	4,292	4,902	343		$9,728	778		2,627	$13,133	30
	SUBTOTAL 1.	**$13,723**	**$4,459**	**$9,677**	**$677**		**$28,535**	**$2,283**		**$6,720**	**$37,538**	**87**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	698	109	411	29		$1,247	100		269	$1,617	4
2.2	Coal Conveyor / Storage	240	54	43	3		$340	27		73	$441	1
2.3	Coal Injection System	9,030	117	937	66		$10,149	1,218	507	1,781	$13,656	32
2.4	Misc.Coal Prep & Feed	340	232	852	60		$1,483	119		401	$2,003	5
2.5	Sorbent Prep Equipment	626	55	258	18		$957	77		207	$1,240	3
2.6	Sorbent Storage & Feed	165		39	3		$206	16		45	$267	1
2.7	Sorbent Injection System	2,850	36	248	17		$3,152	378	158	553	$4,240	10
2.8	Booster Air Supply System	190	86	115	8		$399	32		108	$538	1
2.9	Coal & Sorbent Feed Foundation		1,342	1,163	81		$2,586	207		698	$3,492	8
	SUBTOTAL 2.	**$14,139**	**$2,031**	**$4,066**	**$285**		**$20,520**	**$2,174**	**$665**	**$4,135**	**$27,493**	**64**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	1,163	4,523	1,231	86		$7,003	560		1,135	$8,698	20
3.2	Water Makeup & Pretreating	503	53	294	21		$871	70		188	$1,129	3
3.3	Other Feedwater Subsystems	692	259	240	17		$1,207	97		261	$1,565	4
3.4	Service Water Systems	39	83	297	21		$440	35		95	$570	1
3.5	Other Boiler Plant Systems	1,644	664	1,695	119		$4,121	330		1,113	$5,564	13
3.6	FO Supply Sys & Nat Gas	101	191	368	26		$686	55		148	$890	2
3.7	Waste Treatment Equipment	1,003		597	42		$1,641	131		355	$2,127	5
3.8	Misc. Power Plant Equipment	1,947	263	987	69		$3,266	261		1,058	$4,586	11
	SUBTOTAL 3.	**$7,092**	**$6,037**	**$5,709**	**$400**		**$19,237**	**$1,539**		**$4,352**	**$25,128**	**58**
4	CARBONIZER, PFBC & PFB HTX											
4.1	CARBONIZER	3,070		461	32		$3,563	428	534	679	$5,204	12
4.2	PFB Combustor	1,683		366	26		$2,074	249	311	395	$3,030	7
4.3	PFBC Heat Exchanger	35,452		6,818	477		$42,747	5,130	6,412	8,143	$62,432	145
4.4	Interconnecting Pipe		1,647	1,075	75		$2,797	224		453	$3,474	8
4.5	Misc. PFBC Equipment	392		59	4		$455	55	68	87	$665	2
4.6	Other PFBC Equipment	785	764	550	38		$2,137	171		346	$2,655	6
4.8	Major Component Rigging		1,315	985	69		$2,369	190		384	$2,943	7
4.9	PFBC Structure/Foundation		3,130	1,884	132		$5,146	412		1,389	$6,947	16
	SUBTOTAL 4.	**$41,382**	**$6,856**	**$12,198**	**$854**		**$61,290**	**$6,857**	**$7,326**	**$11,877**	**$87,349**	**203**

	Client:	DEPARTMENT OF ENERGY	Report Date:	23-Jul-99
	Project:	TASK 9-3 CCT Evaluation Guide		12:56 PM

TOTAL PLANT COST SUMMARY

Case:	2gPFBCw/Boost-Max.Power					
Plant Size:	431.3 MW,net	Estimate Type:	Conceptual	Cost Base (Jan)	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Barrier Filters	5,051		543	38		$5,632	451	1,408	1,498	$8,989	21
5.2	Primary & Secondary Cyclones	7,637		796	56		$8,489	679	2,122	2,258	$13,548	31
5.3	Hot Gas Piping		4,394	3,061	214		$7,669	614		1,656	$9,939	23
5.4	Blowback Gas & Air Systems	2,347	420	238	17		$3,021	242	755	804	$4,822	11
5.5	Bag House & Accessories											
5.6	Other BH											
5.9	HGCU Foundations		206	67	5		$278	22		75	$375	1
	SUBTOTAL 5.	**$15,035**	**$5,020**	**$4,704**	**$329**		**$25,088**	**$2,007**	**$4,286**	**$6,291**	**$37,672**	**87**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	56,595		2,874	201		$59,670	4,774	8,950	3,670	$77,063	179
6.2	C.T. Booster Air System & BOA	785	188	156	11		$1,139	91		185	$1,415	3
6.3	Compressed Air Piping		710	863	60		$1,633	131		441	$2,204	5
6.9	Combustion Turbine Foundations		124	145	10		$279	22		90	$391	1
	SUBTOTAL 6.	**$57,379**	**$1,022**	**$4,037**	**$283**		**$62,720**	**$5,018**	**$8,950**	**$4,385**	**$81,074**	**188**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	9,099		950	67		$10,116	809	506	572	$12,002	28
7.2	HRSG Accessories											
7.3	Ductwork		524	459	32		$1,015	81		219	$1,316	3
7.4	Stack	1,514		586	41		$2,142	171		347	$2,660	6
7.9	HRSG,Duct & Stack Foundations		82	102	7		$191	15		52	$258	1
	SUBTOTAL 7.	**$10,613**	**$606**	**$2,098**	**$147**		**$13,464**	**$1,077**	**$506**	**$1,189**	**$16,236**	**38**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	21,145		3,360	235		$24,741	1,979		1,336	$28,056	65
8.2	Turbine Plant Auxiliaries		119	283	20		$422	34		68	$524	1
8.3	Condenser & Auxiliaries	3,189		876	61		$4,126	330		446	$4,902	11
8.4	Steam Piping		4,585	2,465	173		$7,222	578		1,170	$8,970	21
8.9	TG Foundations		243	317	22		$582	47		157	$785	2
	SUBTOTAL 8.	**$24,334**	**$4,947**	**$7,301**	**$511**		**$37,092**	**$2,967**		**$3,177**	**$43,237**	**100**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	3,864		939	66		$4,869	390		789	$6,047	14
9.2	Circulating Water Pumps	609		60	4		$673	54		73	$800	2
9.3	Circ.Water System Auxiliaries	75		11	1		$87	7		19	$113	0
9.4	Circ.Water Piping		1,465	1,681	118		$3,264	261		881	$4,406	10
9.5	Make-up Water System	168		257	18		$443	35		120	$598	1
9.6	Component Cooling Water Sys	162		147	10		$319	26		69	$414	1
9.9	Circ.Water System Foundations		1,088	1,951	137		$3,176	254		857	$4,287	10
	SUBTOTAL 9.	**$4,878**	**$2,553**	**$5,046**	**$353**		**$12,831**	**$1,026**		**$2,808**	**$16,665**	**39**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	w/10.2&10.3		373	26		$400	32		65	$496	1
10.2	Ash Letdown	1,663	8	39	3		$1,713	206		288	$2,206	5
10.3	HGCU Ash Depressurization	3,291	50	169	12		$3,522	282		571	$4,374	10
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	467		524	37		$1,028	82		167	$1,277	3
10.7	Ash Transport & Feed Equipment	609		156	11		$776	62		209	$1,047	2
10.8	Misc. Ash Handling Equipment	968	1,186	365	26		$2,545	204		550	$3,298	8
10.9	Ash/Spent Sorbent Foundation		40	54	4		$98	8		26	$132	0
	SUBTOTAL 10.	**$6,999**	**$1,285**	**$1,681**	**$118**		**$10,081**	**$875**		**$1,875**	**$12,832**	**30**

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		12:56 PM

TOTAL PLANT COST SUMMARY

Case:	2gPFBCw/Boost-Max.Power						
Plant Size:	431.3 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,864		299	21		$2,185	175		236	$2,595	6
11.2	Station Service Equipment	2,640		220	15		$2,875	230		311	$3,416	8
11.3	Switchgear & Motor Control	2,104		354	25		$2,483	199		402	$3,084	7
11.4	Conduit & Cable Tray		1,269	4,026	282		$5,577	446		1,205	$7,228	17
11.5	Wire & Cable		1,362	1,376	96		$2,834	227		612	$3,673	9
11.6	Protective Equipment		107	359	25		$491	39		53	$583	1
11.7	Standby Equipment	277		6	0		$284	23		31	$337	1
11.8	Main Power Transformers	4,444		403	28		$4,876	390		527	$5,792	13
11.9	Electrical Foundations		172	480	34		$685	55		185	$924	2
	SUBTOTAL 11.	**$11,330**	**$2,910**	**$7,524**	**$527**		**$22,290**	**$1,783**		**$3,561**	**$27,634**	**64**
12	INSTRUMENTATION & CONTROL											
12.1	PFBC Control Equipment	184		170	12		$366	4		55	$425	1
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	505		312	22		$839	67		136	$1,043	2
12.5	Signal Processing Equipment	w/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	121		72	5		$198	16		32	$246	1
12.7	Computer & Accessories	4,834		143	10		$4,988	399		539	$5,925	14
12.8	Instrument Wiring & Tubing		1,509	4,741	332		$6,582	527		1,422	$8,530	20
12.9	Other I & C Equipment	890		400	28		$1,318	105		356	$1,779	4
	SUBTOTAL 12.	**$6,535**	**$1,509**	**$5,838**	**$409**		**$14,290**	**$1,118**		**$2,540**	**$17,948**	**42**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		40	1,177	82		$1,299	104		421	$1,824	4
13.2	Site Improvements		603	1,199	84		$1,886	151		611	$2,647	6
13.3	Site Facilities		2,940	3,504	245		$6,689	535		2,167	$9,391	22
	SUBTOTAL 13.		**$3,583**	**$5,880**	**$412**		**$9,874**	**$790**		**$3,199**	**$13,863**	**32**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		295	188	13		$497	40		107	$643	1
14.2	Steam Turbine Building		2,917	2,105	147		$5,170	414		1,117	$6,700	16
14.3	Administration Building		265	217	15		$497	40		107	$645	1
14.4	Circulation Water Pumphouse		87	52	4		$143	11		31	$185	0
14.5	Water Treatment Buildings		551	606	42		$1,200	96		259	$1,555	4
14.6	Machine Shop		226	175	12		$413	33		89	$535	1
14.7	Warehouse		365	266	19		$650	52		140	$842	2
14.8	Other Buildings & Structures		219	192	13		$424	34		92	$550	1
14.9	Waste Treating Building & Str.		489	1,054	74		$1,617	129		349	$2,095	5
	SUBTOTAL 14.		**$5,416**	**$4,855**	**$340**		**$10,610**	**$849**		**$2,292**	**$13,751**	**32**
	TOTAL COST	**$213,438**	**$48,231**	**$80,611**	**$5,643**		**$347,923**	**$30,363**	**$21,733**	**$58,401**	**$458,419**	**1063**

OPERATING LABOR REQUIREMENTS

2gPFBCw/Boost-Max.Power

Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:

Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	8.0	8.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	13.0	13.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA

2gPFBCw/Boost-Max.Power

Item/Description	Consumption Initial	Consumption /Day	Unit Cost
Water(/1000 gallons)		3,839	0.80
Chemicals			
MU & WT Chem.(lbs)	278,748	9,292	0.15
Limestone (ton)	16,095	536.5	16.25
Z Sorb (ton)**			7000.00
Nahcolite(ton)			275.00
Other			
Supplemental Fuel(MBtu)			
Gases,N2 etc.(/100scf)			1.50
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		863	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		3,311	29.63

CONTINGENCY FACTORS

2gPFBCw/Boost-Max.Power

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		21.8
COAL & SORBENT PREP & FEED	3.2	17.7
FEEDWATER & MISC. BOP SYSTEMS		20.9
CARBONIZER, PFBC & PFB HTX		
CARBONIZER	15.0	15.0
PFB Combustor	15.0	15.0
PFBC Heat Exchanger	15.0	15.0
Other PFBC Equipment	0.5	19.0
HOT GAS CLEANUP & PIPING	17.1	20.0
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	15.0	5.0
C.T. Booster Air System & BOA		21.7
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator	5.0	5.0
HRSG Accessories, Ductwork and Stack		17.1
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		13.8
COOLING WATER SYSTEM		20.3
ASH/SPENT SORBENT HANDLING SYS		17.1
ACCESSORY ELECTRIC PLANT		14.8
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS 2gPFBCw/Boost-Max.Power	
Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.1
COAL & SORBENT PREP & FEED	2.9
FEEDWATER & MISC. BOP SYSTEMS	1.9
CARBONIZER, PFBC & PFB HTX	
CARBONIZER	5.0
PFB Combustor	4.5
PFBC Heat Exchanger	4.0
Other PFBC Equipment	1.6
HOT GAS CLEANUP & PIPING	6.7
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	7.3
C.T. Booster Air System & BOA	2.0
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.4
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.3
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.3
BUILDINGS & STRUCTURES	1.4

CPFBC - Maximum Efficiency

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	2gPFBCw/Boost-Max.Efficiency			
Plant Size:	379.0 (MW,net)	HeatRate:	7,273	(Btu/kWh)
Primary/Secondary Fuel(type):	Illinois #6	Cost:	1.27	($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005	(Jan.)
Capacity Factor:	85 (%)			

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		316,992	836.4
Engineering(incl.C.M.,H.O.& Fee)		27,444	72.4
Process Contingency		20,166	53.2
Project Contingency		52,944	139.7
TOTAL PLANT COST(TPC)		$417,545	1101.7
TOTAL CASH EXPENDED	$417,545		
AFDC	$26,773		
TOTAL PLANT INVESTMENT(TPI)		$444,318	1172.4
Royalty Allowance			
Preproduction Costs		11,073	29.2
Inventory Capital		3,599	9.5
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.2
TOTAL CAPITAL REQUIREMENT(TCR)		$459,441	1212.3

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**		**$/kW-yr**
Operating Labor	3,871		10.2
Maintenance Labor	2,700		7.1
Maintenance Material	4,050		10.7
Administrative & Support Labor	1,643		4.3
TOTAL OPERATION & MAINTENANCE	$12,264		32.4
FIXED O & M		27.51	$/kW-yr
VARIABLE O & M		0.07	¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	759	0.03
Chemicals	2,772	0.10
Other Consumables		
Waste Disposal	2,340	0.08
TOTAL CONSUMABLE OPERATING COSTS	$5,872	0.21
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$26,065	0.92

	1st Year (2005 $)		**Levelized (10th.Year $)**	
PRODUCTION COST SUMMARY		**¢/kWh**		**¢/kWh**
Fixed O & M	27.5/kW-yr	0.37	27.5/kW-yr	0.37
Variable O & M		0.07		0.07
Consumables		0.21		0.21
By-product Credit				
Fuel		0.85		0.80
TOTAL PRODUCTION COST		1.49		1.44
LEVELIZED CARRYING CHARGES(Capital)			183.1/kW-yr	2.46
LEVELIZED (10th.Year) BUSBAR COST OF POWER				3.90

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS				
GENERAL DATA/CHARACTERISTICS				
Case Title:	2gPFBCw/Boost-Max.Efficiency			
Unit Size:/Plant Size:	379.0	MW,net	379.0	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	7,273	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre
FINANCIAL CRITERIA				
Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		
Capital Structure	% of Total		Cost(%)	
Common Equity	20		16.5	
Preferred Stock				
Debt	80		6.3	
Weighted Cost of Capital:(after tax)		6.4 %		
	Over Book Life		1999 to 2005	
Escalation Rates — General		% per year		% per year
Primary Fuel	-1.4	% per year	-1.34	% per year
Secondary Fuel	0.7	% per year	1.07	% per year

Client: DEPARTMENT OF ENERGY
Project: TASK 9-3 CCT Evaluation Guide

Report Date: 23-Jul-99
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TOTAL PLANT COST SUMMARY

Case: 2gPFBCw/Boost-Max.Efficiency
Plant Size: 379.0 MW,net **Estimate Type:** Conceptual **Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,411		1,353	95		$3,859	309		834	$5,001	13
1.2	Coal Stackout & Reclaim	3,116		867	61		$4,044	324		873	$5,241	14
1.3	Coal Conveyors & Yd Crush	2,897		858	60		$3,815	305		824	$4,945	13
1.4	Other Coal Handling	758		199	14		$970	78		210	$1,258	3
1.5	Sorbent Receive & Unload	57		21	1		$79	6		17	$102	0
1.6	Sorbent Stackout & Reclaim	1,787		601	42		$2,430	194		525	$3,149	8
1.7	Sorbent Conveyors	1,077	94	288	20		$1,480	118		320	$1,918	5
1.8	Other Sorbent Handling	281	62	181	13		$537	43		145	$725	2
1.9	Coal & Sorbent Hnd.Foundations	174	3,898	4,452	312		$8,836	707		2,386	$11,928	31
	SUBTOTAL 1.	**$12,557**	**$4,054**	**$8,821**	**$617**		**$26,049**	**$2,084**		**$6,133**	**$34,266**	**90**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	630	98	371	26		$1,126	90		243	$1,459	4
2.2	Coal Conveyor / Storage	217	49	39	3		$307	25		66	$398	1
2.3	Coal Injection System	8,199	106	851	60		$9,215	1,106	461	1,617	$12,399	33
2.4	Misc.Coal Prep & Feed	307	209	769	54		$1,339	107		362	$1,808	5
2.5	Sorbent Prep Equipment	585	52	241	17		$894	72		193	$1,159	3
2.6	Sorbent Storage & Feed	154		36	3		$193	15		42	$250	1
2.7	Sorbent Injection System	2,699	34	235	16		$2,985	358	149	524	$4,016	11
2.8	Booster Air Supply System	177	83	111	8		$379	30		102	$512	1
2.9	Coal & Sorbent Feed Foundation		1,212	1,050	73		$2,335	187		630	$3,152	8
	SUBTOTAL 2.	**$12,969**	**$1,843**	**$3,703**	**$259**		**$18,773**	**$1,990**	**$610**	**$3,780**	**$25,153**	**66**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	980	3,813	1,038	73		$5,904	472		956	$7,332	19
3.2	Water Makeup & Pretreating	428	45	250	18		$741	59		160	$960	3
3.3	Other Feedwater Subsystems	583	218	202	14		$1,018	81		220	$1,319	3
3.4	Service Water Systems	33	71	253	18		$374	30		81	$485	1
3.5	Other Boiler Plant Systems	1,399	565	1,443	101		$3,507	281		947	$4,735	12
3.6	FO Supply Sys & Nat Gas	94	178	341	24		$637	51		138	$825	2
3.7	Waste Treatment Equipment	853		508	36		$1,397	112		302	$1,810	5
3.8	Misc. Power Plant Equipment	1,806	244	915	64		$3,030	242		982	$4,254	11
	SUBTOTAL 3.	**$6,177**	**$5,133**	**$4,950**	**$346**		**$16,607**	**$1,329**		**$3,785**	**$21,720**	**57**
4	CARBONIZER, PFBC & PFB HTX											
4.1	CARBONIZER	3,058		459	32		$3,549	426	532	676	$5,183	14
4.2	PFB Combustor	1,687		366	26		$2,079	250	312	396	$3,037	8
4.3	PFBC Heat Exchanger	27,240		5,239	367		$32,845	3,941	4,927	6,257	$47,971	127
4.4	Interconnecting Pipe		1,466	957	67		$2,490	199		403	$3,093	8
4.5	Misc. PFBC Equipment	392		59	4		$455	55	68	87	$665	2
4.6	Other PFBC Equipment	699	680	489	34		$1,902	152		308	$2,363	6
4.8	Major Component Rigging		1,217	911	64		$2,192	175		355	$2,723	7
4.9	PFBC Structure/Foundation		2,896	1,744	122		$4,762	381		1,286	$6,428	17
	SUBTOTAL 4.	**$33,076**	**$6,259**	**$10,225**	**$716**		**$50,276**	**$5,579**	**$5,839**	**$9,768**	**$71,463**	**189**

Client:	DEPARTMENT OF ENERGY			**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide				12:53 PM

TOTAL PLANT COST SUMMARY

Case:	2gPFBCw/Boost-Max.Efficiency						
Plant Size:	379.0 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Barrier Filters	5,051		543	38		$5,632	451	1,408	1,498	$8,989	24
5.2	Primary & Secondary Cyclones	7,637		796	56		$8,489	679	2,122	2,258	$13,548	36
5.3	Hot Gas Piping		4,350	3,030	212		$7,592	607		1,640	$9,839	26
5.4	Blowback Gas & Air Systems	2,316	413	234	16		$2,980	238	745	793	$4,756	13
5.5	Bag House & Accessories											
5.6	Other BH											
5.9	HGCU Foundations		204	66	5		$275	22		74	$371	1
	SUBTOTAL 5.	**$15,004**	**$4,967**	**$4,669**	**$327**		**$24,967**	**$1,997**	**$4,275**	**$6,263**	**$37,503**	**99**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	56,511		2,874	201		$59,586	4,767	8,938	3,665	$76,955	203
6.2	C.T. Booster Air System & BOA	785	188	156	11		$1,139	91		185	$1,415	4
6.3	Compressed Air Piping		710	863	60		$1,633	131		441	$2,204	6
6.9	Combustion Turbine Foundations		124	144	10		$278	22		90	$391	1
	SUBTOTAL 6.	**$57,296**	**$1,022**	**$4,036**	**$283**		**$62,636**	**$5,011**	**$8,938**	**$4,380**	**$80,965**	**214**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	9,051		945	66		$10,062	805	503	569	$11,939	32
7.2	HRSG Accessories											
7.3	Ductwork		529	463	32		$1,024	82		221	$1,327	4
7.4	Stack	1,527		591	41		$2,160	173		350	$2,683	7
7.9	HRSG,Duct & Stack Foundations		83	103	7		$193	15		52	$261	1
	SUBTOTAL 7.	**$10,578**	**$612**	**$2,103**	**$147**		**$13,440**	**$1,075**	**$503**	**$1,192**	**$16,210**	**43**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	17,098		2,717	190		$20,005	1,600		1,080	$22,686	60
8.2	Turbine Plant Auxiliaries		100	238	17		$355	28		58	$441	1
8.3	Condenser & Auxiliaries	2,684		738	52		$3,473	278		375	$4,126	11
8.4	Steam Piping		3,859	2,075	145		$6,079	486		985	$7,550	20
8.9	TG Foundations		204	266	19		$489	39		132	$661	2
	SUBTOTAL 8.	**$19,782**	**$4,164**	**$6,034**	**$422**		**$30,401**	**$2,432**		**$2,630**	**$35,463**	**94**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	3,276		796	56		$4,127	330		669	$5,126	14
9.2	Circulating Water Pumps	516		51	4		$571	46		62	$678	2
9.3	Circ.Water System Auxiliaries	64		9	1		$74	6		16	$95	0
9.4	Circ.Water Piping		1,242	1,425	100		$2,767	221		747	$3,735	10
9.5	Make-up Water System	143		218	15		$376	30		101	$507	1
9.6	Component Cooling Water Sys	137		125	9		$270	22		58	$351	1
9.9	Circ.Water System Foundations		922	1,654	116		$2,692	215		727	$3,634	10
	SUBTOTAL 9.	**$4,135**	**$2,164**	**$4,278**	**$299**		**$10,877**	**$870**		**$2,380**	**$14,127**	**37**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	w/10.2&10.3		347	24		$371	30		60	$461	1
10.2	Ash Letdown	1,545	8	36	3		$1,592	191		267	$2,050	5
10.3	HGCU Ash Depressurization	3,058	46	157	11		$3,272	262		530	$4,064	11
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	433		486	34		$954	76		155	$1,185	3
10.7	Ash Transport & Feed Equipment	565		145	10		$720	58		194	$972	3
10.8	Misc. Ash Handling Equipment	898	1,100	339	24		$2,361	189		510	$3,060	8
10.9	Ash/Spent Sorbent Foundation		37	50	3		$91	7		24	$122	0
	SUBTOTAL 10.	**$6,500**	**$1,192**	**$1,560**	**$109**		**$9,361**	**$813**		**$1,741**	**$11,914**	**31**

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		12:53 PM

TOTAL PLANT COST SUMMARY

Case:	2gPFBCw/Boost-Max.Efficiency		
Plant Size:	379.0 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)** 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,730		278	19		$2,027	162		219	$2,409	6
11.2	Station Service Equipment	2,497		208	15		$2,719	218		294	$3,230	9
11.3	Switchgear & Motor Control	1,990		335	23		$2,349	188		380	$2,917	8
11.4	Conduit & Cable Tray		1,200	3,808	267		$5,275	422		1,139	$6,836	18
11.5	Wire & Cable		1,288	1,301	91		$2,680	214		579	$3,474	9
11.6	Protective Equipment		98	329	23		$449	36		49	$534	1
11.7	Standby Equipment	253		6	0		$259	21		28	$308	1
11.8	Main Power Transformers	4,065		369	26		$4,459	357		482	$5,298	14
11.9	Electrical Foundations		157	439	31		$626	50		169	$845	2
	SUBTOTAL 11.	**$10,535**	**$2,743**	**$7,071**	**$495**		**$20,844**	**$1,668**		**$3,339**	**$25,851**	**68**
12	INSTRUMENTATION & CONTROL											
12.1	PFBC Control Equipment	184		163	11		$359	4		54	$417	1
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	486		300	21		$807	65		131	$1,002	3
12.5	Signal Processing Equipment	w/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	117		69	5		$190	15		31	$237	1
12.7	Computer & Accessories	4,647		138	10		$4,795	384		518	$5,696	15
12.8	Instrument Wiring & Tubing		1,450	4,557	319		$6,327	506		1,367	$8,199	22
12.9	Other I & C Equipment	855		384	27		$1,267	101		342	$1,710	5
	SUBTOTAL 12.	**$6,289**	**$1,450**	**$5,612**	**$393**		**$13,744**	**$1,075**		**$2,442**	**$17,262**	**46**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		38	1,108	78		$1,223	98		396	$1,717	5
13.2	Site Improvements		568	1,128	79		$1,775	142		575	$2,492	7
13.3	Site Facilities		2,767	3,298	231		$6,296	504		2,040	$8,839	23
	SUBTOTAL 13.		**$3,372**	**$5,534**	**$387**		**$9,293**	**$743**		**$3,011**	**$13,048**	**34**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		295	188	13		$497	40		107	$643	2
14.2	Steam Turbine Building		2,532	1,827	128		$4,487	359		969	$5,815	15
14.3	Administration Building		254	208	15		$477	38		103	$618	2
14.4	Circulation Water Pumphouse		84	50	3		$137	11		30	$177	0
14.5	Water Treatment Buildings		529	581	41		$1,151	92		249	$1,491	4
14.6	Machine Shop		217	167	12		$396	32		86	$513	1
14.7	Warehouse		350	255	18		$623	50		135	$807	2
14.8	Other Buildings & Structures		210	184	13		$407	33		88	$527	1
14.9	Waste Treating Building & Str.		469	1,010	71		$1,550	124		335	$2,009	5
	SUBTOTAL 14.		**$4,940**	**$4,471**	**$313**		**$9,724**	**$778**		**$2,100**	**$12,602**	**33**
	TOTAL COST	**$194,897**	**$43,914**	**$73,066**	**$5,115**		**$316,992**	**$27,444**	**$20,166**	**$52,944**	**$417,545**	**1102**

OPERATING LABOR REQUIREMENTS		
2gPFBCw/Boost-Max.Efficiency		
Operating Labor Rate(base):	26.15 $/hour	
Operating Labor Burden:	30.00 % of base	
Labor O-H Charge Rate:	25.00 % of labor	
Operating Labor Requirements(O.J.)per Shift:		Total
Category	1 unit/mod.	Plant
Skilled Operator	2.0	2.0
Operator	8.0	8.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	13.0	13.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA			
2gPFBCw/Boost-Max.Efficiency			
	Consumption		Unit
Item/Description	Initial	/Day	Cost
Water(/1000 gallons)		3,058	0.80
Chemicals			
MU & WT Chem.(lbs)	222,068	7,402	0.15
Limestone (ton)	14,503	483.4	16.25
Z Sorb (ton)**			7000.00
Nahcolite(ton)			275.00
Other			
Supplemental Fuel(MBtu)			
Gases,N2 etc.(/100scf)			1.50
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		754	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		2,835	29.63

CONTINGENCY FACTORS		
2gPFBCw/Boost-Max.Efficiency		
	Contingency Factors(%)	
Item/Description	%Process	%Project
COAL & SORBENT HANDLING		21.8
COAL & SORBENT PREP & FEED	3.2	17.7
FEEDWATER & MISC. BOP SYSTEMS		21.1
CARBONIZER, PFBC & PFB HTX		
CARBONIZER	15.0	15.0
PFB Combustor	15.0	15.0
PFBC Heat Exchanger	15.0	15.0
Other PFBC Equipment	0.6	19.0
HOT GAS CLEANUP & PIPING	17.1	20.0
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	15.0	5.0
C.T. Booster Air System & BOA		21.7
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator	5.0	5.0
HRSG Accessories, Ductwork and Stack		17.1
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		13.8
COOLING WATER SYSTEM		20.3
ASH/SPENT SORBENT HANDLING SYS		17.1
ACCESSORY ELECTRIC PLANT		14.8
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS	
2gPFBCw/Boost-Max.Efficiency	
Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.1
COAL & SORBENT PREP & FEED	2.9
FEEDWATER & MISC. BOP SYSTEMS	1.9
CARBONIZER, PFBC & PFB HTX	
CARBONIZER	5.0
PFB Combustor	4.5
PFBC Heat Exchanger	4.0
Other PFBC Equipment	1.6
HOT GAS CLEANUP & PIPING	6.7
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	7.3
C.T. Booster Air System & BOA	2.0
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.4
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.3
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.3
BUILDINGS & STRUCTURES	1.4

PFBC - Bubbling Bed

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	BBPFB (P800)		
Plant Size:	424.6 (MW,net)	HeatRate:	8,354 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	2.5 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		438,219	1032.0
Engineering(incl.C.M.,H.O.& Fee)		19,291	45.4
Process Contingency			
Project Contingency		66,885	157.5
TOTAL PLANT COST(TPC)		$524,396	1235.0
TOTAL CASH EXPENDED	$524,396		
AFDC	$33,624		
TOTAL PLANT INVESTMENT(TPI)		$558,020	1314.2
Royalty Allowance			
Preproduction Costs		13,849	32.6
Inventory Capital		4,659	11.0
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.1
TOTAL CAPITAL REQUIREMENT(TCR)		$576,978	1358.8

OPERATING & MAINTENANCE COSTS (1999 Dollars)	$x1000	$/kW-yr
Operating Labor	3,871	9.1
Maintenance Labor	2,849	6.7
Maintenance Material	4,274	10.1
Administrative & Support Labor	1,680	4.0
TOTAL OPERATION & MAINTENANCE	$12,674	29.8
FIXED O & M		25.37 $/kW-yr
VARIABLE O & M		0.06 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	$x1000	¢/kWh
Water	1,231	0.04
Chemicals	4,289	0.14
Other Consumables		
Waste Disposal	3,398	0.11
TOTAL CONSUMABLE OPERATING COSTS	$8,917	0.28
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$33,544	1.06

PRODUCTION COST SUMMARY	1st Year (2005 $)	¢/kWh	Levelized (10th.Year $)	¢/kWh
Fixed O & M	25.4/kW-yr	0.34	25.4/kW-yr	0.34
Variable O & M		0.06		0.06
Consumables		0.28		0.28
By-product Credit				
Fuel		0.98		0.91
TOTAL PRODUCTION COST		1.66		1.60
LEVELIZED CARRYING CHARGES(Capital)			205.2/kW-yr	2.76
LEVELIZED (10th.Year) BUSBAR COST OF POWER				4.35

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	BBPFB (P800)			
Unit Size:/Plant Size:	424.6	MW,net	424.6	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	8,354	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	2.5	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total		Cost(%)
Common Equity	20		16.5
Preferred Stock			
Debt	80		6.3
Weighted Cost of Capital:(after tax)		6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

	Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
	Project:	TASK 9-3 CCT Evaluation Guide		12:58 PM
	Case:	BBPFB (P800)		
	Plant Size:	424.6 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)** 1999 ($x1000)

TOTAL PLANT COST SUMMARY

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,819		1,582	111		$4,513	361		975	$5,848	14
1.2	Coal Stackout & Reclaim	3,643		1,014	71		$4,729	378		1,021	$6,128	14
1.3	Coal Conveyors & Yd Crush	3,387		1,004	70		$4,461	357		964	$5,782	14
1.4	Other Coal Handling	886		232	16		$1,135	91		245	$1,471	3
1.5	Sorbent Receive & Unload	95		35	2		$133	11		29	$172	0
1.6	Sorbent Stackout & Reclaim	2,554		859	60		$3,472	278		750	$4,500	11
1.7	Sorbent Conveyors	906		242	17		$1,165	93		252	$1,509	4
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations		4,558	5,206	364		$10,129	810		2,735	$13,674	32
	SUBTOTAL 1.	**$14,290**	**$4,558**	**$10,175**	**$712**		**$29,735**	**$2,379**		**$6,970**	**$39,084**	**92**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying											
2.2	Coal Conveyor / Storage	551		161	11		$724	58		156	$938	2
2.3	Coal Injection System	25,689		8,769	614		$35,072	403		5,321	$40,796	96
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment	774	68	318	22		$1,182	95		255	$1,532	4
2.6	Sorbent Storage & Feed	204		48	3		$255	20		55	$330	1
2.7	Sorbent Injection System	w/2.3		w/2.3								
2.8	Booster Air Supply System	235					$235	19			$253	1
2.9	Coal & Sorbent Feed Foundation		600	520	36		$1,157	93		312	$1,562	4
	SUBTOTAL 2.	**$27,452**	**$669**	**$9,816**	**$687**		**$38,624**	**$688**		**$6,100**	**$45,412**	**107**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	3,170	1,407	1,483	104		$6,164	493		999	$7,655	18
3.2	Water Makeup & Pretreating	603	64	353	25		$1,044	84		226	$1,353	3
3.3	Other Feedwater Subsystems	2,339	588	1,063	74		$4,065	325		878	$5,268	12
3.4	Service Water Systems	47	100	356	25		$527	42		114	$683	2
3.5	Other Boiler Plant Systems	1,971	796	2,033	142		$4,942	395		1,334	$6,672	16
3.6	FO Supply Sys & Nat Gas	101	191	367	26		$684	55		148	$886	2
3.7	Waste Treatment Equipment	1,202		716	50		$1,968	157		425	$2,551	6
3.8	Misc. Power Plant Equipment	1,939	262	982	69		$3,253	260		1,054	$4,567	11
	SUBTOTAL 3.	**$11,372**	**$3,407**	**$7,353**	**$515**		**$22,647**	**$1,812**		**$5,177**	**$29,636**	**70**
4	CARBONIZER, PFBC & PFB HTX											
4.1	PFB PRESSURE VESSEL	11,518		17,743	1,242		$30,503	351		4,628	$35,481	84
4.2	PFBC Boiler	23,652		14,981	1,049		$39,681	456		6,021	$46,158	109
4.3	PFBC Economizer	13,163		8,287	580		$22,030	253		3,343	$25,626	60
4.4	Interconnecting Pipe											
4.5	Misc. PFBC Equipment	3,352		1,700	119		$5,171	59		785	$6,015	14
4.6	Other PFBC Equipment											
4.8	Major Component Rigging											
4.9	PFBC Structure/Foundation		3,693	2,224	156		$6,073	486		1,640	$8,198	19
	SUBTOTAL 4.	**$51,685**	**$3,693**	**$44,934**	**$3,145**		**$103,458**	**$1,606**		**$16,415**	**$121,479**	**286**

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		12:58 PM

TOTAL PLANT COST SUMMARY

Case:	BBPFB (P800)				
Plant Size:	424.6 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Barrier Filters	N/A		NA								
5.2	Primary & Secondary Cyclones	w/4.2		w/4.2								
5.3	Hot Gas Piping		w/6.1	w/6.1								
5.4	Blowback Gas & Air Systems											
5.5	Bag House & Accessories	8,630		3,323	233		$12,186	975		1,974	$15,136	36
5.6	Other BH		2,244	3,918	274		$6,437	515		1,043	$7,994	19
5.9	HGCU Foundations		w/5.6	w/5.6								
	SUBTOTAL 5.	**$8,630**	**$2,244**	**$7,242**	**$507**		**$18,623**	**$1,490**		**$3,017**	**$23,130**	**54**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	43,157		14,556	1,019		$58,732	617		2,967	$62,316	147
6.2	C.T. Booster Air System & BOA											
6.3	Compressed Air Piping		w/6.1	w/6.1								
6.9	Combustion Turbine Foundations		139	162	11		$312	25		101	$439	1
	SUBTOTAL 6.	**$43,157**	**$139**	**$14,718**	**$1,030**		**$59,044**	**$642**		**$3,069**	**$62,755**	**148**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2	HRSG Accessories											
7.3	Ductwork		w/4.1	w/4.1								
7.4	Stack	1,369		530	37		$1,936	155		314	$2,405	6
7.9	HRSG,Duct & Stack Foundations		194	196	14		$404	32		109	$545	1
	SUBTOTAL 7.	**$1,369**	**$194**	**$726**	**$51**		**$2,340**	**$187**		**$423**	**$2,949**	**7**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	30,705		4,879	342		$35,925	2,874		1,940	$40,739	96
8.2	Turbine Plant Auxiliaries		161	383	27		$571	46		92	$709	2
8.3	Condenser & Auxiliaries	4,315		1,186	83		$5,584	447		603	$6,634	16
8.4	Steam Piping		6,204	3,336	234		$9,774	782		1,583	$12,139	29
8.9	TG Foundations		329	428	30		$787	63		212	$1,062	3
	SUBTOTAL 8.	**$35,020**	**$6,694**	**$10,212**	**$715**		**$52,641**	**$4,211**		**$4,431**	**$61,283**	**144**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	5,165		1,255	88		$6,508	521		1,054	$8,083	19
9.2	Circulating Water Pumps	814		81	6		$900	72		97	$1,069	3
9.3	Circ.Water System Auxiliaries	100		15	1		$116	9		25	$151	0
9.4	Circ.Water Piping		1,958	2,246	157		$4,362	349		1,178	$5,889	14
9.5	Make-up Water System	225		343	24		$592	47		160	$800	2
9.6	Component Cooling Water Sys	216		196	14		$426	34		92	$553	1
9.9	Circ.Water System Foundations		1,454	2,608	183		$4,245	340		1,146	$5,730	13
	SUBTOTAL 9.	**$6,520**	**$3,412**	**$6,745**	**$472**		**$17,150**	**$1,372**		**$3,752**	**$22,274**	**52**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	w/4.2		w/4.2								
10.2	Ash Letdown	13,199		6,693	469		$20,361	234		3,089	$23,684	56
10.3	HGCU Ash Depressurization	w/10.2		w/10.2								
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos	533		598	42		$1,173	94		190	$1,457	3
10.7	Ash Transport & Feed Equipment											
10.8	Misc. Ash Handling Equipment											
10.9	Ash/Spent Sorbent Foundation		46	61	4		$111	9		30	$150	0
	SUBTOTAL 10.	**$13,732**	**$46**	**$7,353**	**$515**		**$21,645**	**$337**		**$3,309**	**$25,292**	**60**

Client:	DEPARTMENT OF ENERGY			**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide				12:58 PM

TOTAL PLANT COST SUMMARY

Case:	BBPFB (P800)					
Plant Size:	424.6 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)

Acct		Equipment	Material	Labor		Sales	Bare Erected	Eng'g CM	Contingencies		TOTAL PLANT COST	
No.	Item/Description	Cost	Cost	Direct	Indirect	Tax	Cost $	H.O.& Fee	Process	Project	$	$/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,857		298	21		$2,176	174		235	$2,585	6
11.2	Station Service Equipment	2,780		232	16		$3,028	242		327	$3,597	8
11.3	Switchgear & Motor Control	2,216		373	26		$2,615	209		424	$3,248	8
11.4	Conduit & Cable Tray		1,336	4,240	297		$5,873	470		1,269	$7,611	18
11.5	Wire & Cable		1,435	1,449	101		$2,985	239		645	$3,868	9
11.6	Protective Equipment		106	358	25		$489	39		53	$581	1
11.7	Standby Equipment	275		6	0		$282	23		30	$335	1
11.8	Main Power Transformers	4,423		401	28		$4,852	388		524	$5,764	14
11.9	Electrical Foundations		171	477	33		$681	55		184	$920	2
	SUBTOTAL 11.	**$11,551**	**$3,048**	**$7,833**	**$548**		**$22,980**	**$1,838**		**$3,690**	**$28,509**	**67**
12	INSTRUMENTATION & CONTROL											
12.1	PFBC Control Equipment	15,594		2,019	141		$17,754	204		2,694	$20,652	49
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control											
12.5	Signal Processing Equipment	w/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	119		71	5		$194	16		31	$241	1
12.7	Computer & Accessories	948		28	2		$978	78		106	$1,162	3
12.8	Instrument Wiring & Tubing		1,480	4,650	326		$6,456	516		1,394	$8,367	20
12.9	Other I & C Equipment	873		392	27		$1,292	103		349	$1,745	4
	SUBTOTAL 12.	**$17,534**	**$1,480**	**$7,160**	**$501**		**$26,675**	**$918**		**$4,574**	**$32,168**	**76**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		40	1,173	82		$1,295	104		420	$1,818	4
13.2	Site Improvements		601	1,195	84		$1,879	150		609	$2,639	6
13.3	Site Facilities		2,930	3,492	244		$6,667	533		2,160	$9,360	22
	SUBTOTAL 13.		**$3,571**	**$5,860**	**$410**		**$9,841**	**$787**		**$3,189**	**$13,817**	**33**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		572	636	45		$1,253	100		271	$1,624	4
14.2	Steam Turbine Building		3,740	2,700	189		$6,629	530		1,432	$8,591	20
14.3	Administration Building		265	216	15		$496	40		107	$643	2
14.4	Circulation Water Pumphouse		87	52	4		$142	11		31	$185	0
14.5	Water Treatment Buildings		550	605	42		$1,197	96		259	$1,552	4
14.6	Machine Shop		226	174	12		$412	33		89	$534	1
14.7	Warehouse		365	265	19		$648	52		140	$840	2
14.8	Other Buildings & Structures		218	192	13		$423	34		91	$549	1
14.9	Waste Treating Building & Str.		488	1,051	74		$1,613	129		348	$2,090	5
	SUBTOTAL 14.		**$6,512**	**$5,891**	**$412**		**$12,815**	**$1,025**		**$2,768**	**$16,608**	**39**
	TOTAL COST	**$242,312**	**$39,667**	**$146,018**	**$10,221**		**$438,219**	**$19,291**		**$66,885**	**$524,396**	**1235**

OPERATING LABOR REQUIREMENTS		
BBPFB (P800)		
Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift: Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	8.0	8.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	13.0	13.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA			
BBPFB (P800)			
	Consumption		Unit
Item/Description	Initial	/Day	Cost
Water(/1000 gallons)		4,958	0.80
Chemicals			
MU & WT Chem.(lbs)	359,987	12,000	0.15
Limestone (ton)	22,286	742.9	16.25
Z Sorb (ton)**			7000.00
Nahcolite(ton)			275.00
Other			
Supplemental Fuel(MBtu)			
Gases,N2 etc.(/100scf)			1.50
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)		1,095	10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(ton)		3,649	29.63

CONTINGENCY FACTORS

BBPFB (P800)

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		21.7
COAL & SORBENT PREP & FEED		15.5
FEEDWATER & MISC. BOP SYSTEMS		21.2
CARBONIZER, PFBC & PFB HTX		
PFB PRESSURE VESSEL		15.0
PFBC Boiler		15.0
PFBC Economizer		15.0
Other PFBC Equipment		20.6
HOT GAS CLEANUP & PIPING		15.0
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator		5.0
C.T. Booster Air System & BOA		30.0
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		
HRSG Accessories, Ductwork and Stack		16.7
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		13.8
COOLING WATER SYSTEM		20.3
ASH/SPENT SORBENT HANDLING SYS		15.1
ACCESSORY ELECTRIC PLANT		14.9
INSTRUMENTATION & CONTROL		16.6
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS

BBPFB (P800)

Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.1
COAL & SORBENT PREP & FEED	3.4
FEEDWATER & MISC. BOP SYSTEMS	2.1
CARBONIZER, PFBC & PFB HTX	
PFB PRESSURE VESSEL	5.0
PFBC Boiler	4.5
PFBC Economizer	4.0
Other PFBC Equipment	1.9
HOT GAS CLEANUP & PIPING	3.3
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	2.5
C.T. Booster Air System & BOA	0.5
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	
HRSG Accessories, Ductwork and Stack	1.3
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.5
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.9
IMPROVEMENTS TO SITE	1.3
BUILDINGS & STRUCTURES	1.4

Natural Gas Combined Cycle (CTCC)

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	CTCC - West."G"		
Plant Size:	323.4 (MW,net)	HeatRate:	6,827 (Btu/kWh)
Primary/Secondary Fuel(type):	Nat.Gas	Cost:	2.76 ($/MMBtu)
Design/Construction:	2.25 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		143,762	444.5
Engineering(incl.C.M.,H.O.& Fee)		11,501	35.6
Process Contingency			
Project Contingency		19,123	59.1
TOTAL PLANT COST(TPC)		$174,386	539.2
TOTAL CASH EXPENDED	$174,386		
AFDC	$6,797		
TOTAL PLANT INVESTMENT(TPI)		$181,183	560.2
Royalty Allowance			
Preproduction Costs		5,261	16.3
Inventory Capital		488	1.5
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		150	0.5
TOTAL CAPITAL REQUIREMENT(TCR)		$187,082	578.5

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	1,489	4.6
Maintenance Labor	984	3.0
Maintenance Material	1,476	4.6
Administrative & Support Labor	618	1.9
TOTAL OPERATION & MAINTENANCE	$4,566	14.1
FIXED O & M		12.00 $/kW-yr
VARIABLE O & M		0.03 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	511	0.02
Chemicals	226	0.01
Other Consumables		
Waste Disposal		
TOTAL CONSUMABLE OPERATING COSTS	$736	0.03
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$45,343	1.88

PRODUCTION COST SUMMARY	**1st Year (2005 $)**	**¢/kWh**	**Levelized (10th.Year $)**	**¢/kWh**
Fixed O & M	12.0/kW-yr	0.16	12.0/kW-yr	0.16
Variable O & M		0.03		0.03
Consumables		0.03		0.03
By-product Credit				
Fuel		2.01		2.07
TOTAL PRODUCTION COST		2.23		2.29
LEVELIZED CARRYING CHARGES(Capital)			87.3/kW-yr	1.17
LEVELIZED (10th.Year) BUSBAR COST OF POWER				3.47

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	CTCC - West."G"			
Unit Size:/Plant Size:	323.4	MW,net	323.4	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Nat.Gas			
Energy From Primary/Secondary Fuels	6,827	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	2.76	$/MBtu		$/MBtu
Design/Construction Period:	2.25	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	100	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	0.7	% per year	1.07	% per year
	Secondary Fuel		% per year		% per year

Client:	DEPARTMENT OF ENERGY	**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide		01:02 PM

TOTAL PLANT COST SUMMARY

Case:	CTCC - West."G"						
Plant Size:	323.4 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)	

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload											
1.2	Coal Stackout & Reclaim											
1.3	Coal Conveyors & Yd Crush											
1.4	Other Coal Handling											
1.5	Sorbent Receive & Unload											
1.6	Sorbent Stackout & Reclaim											
1.7	Sorbent Conveyors											
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations											
	SUBTOTAL 1.											
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying											
2.2	Prepared Coal Storage & Feed											
2.3	Slurry Prep & Feed											
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment											
2.6	Sorbent Storage & Feed											
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation											
	SUBTOTAL 2.											
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	585	2,277	620	43		$3,526	282		571	$4,379	14
3.2	Water Makeup & Pretreating	250	26	146	10		$433	35		93	$561	2
3.3	Other Feedwater Subsystems	348	130	121	8		$608	49		131	$788	2
3.4	Service Water Systems	19	41	148	10		$218	17		47	$283	1
3.5	Other Boiler Plant Systems	817	330	842	59		$2,047	164		553	$2,764	9
3.6	Natural Gas Supply & FO Sys.	4,377	158	304	21		$4,861	389		1,050	$6,300	19
3.7	Waste Treatment Equipment	498		297	21		$815	65		176	$1,057	3
3.8	Misc. Power Plant Equipment	1,611	218	816	57		$2,702	216		875	$3,794	12
	SUBTOTAL 3.	**$8,505**	**$3,181**	**$3,293**	**$231**		**$15,210**	**$1,217**		**$3,497**	**$19,924**	**62**
4	GASIFIER & ACCESSORIES											
4.1	Gasifier & Auxiliaries(Destec)											
4.2	High Temperature Cooling											
4.3	ASU/Oxidant Compression	N/A		N/A								
4.4	Booster Air Compression											
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2								
4.6	Other Gasification Equipment											
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2								
4.9	Gasification Foundations											
	SUBTOTAL 4.											

Client: DEPARTMENT OF ENERGY
Project: TASK 9-3 CCT Evaluation Guide

Report Date: 23-Jul-99
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TOTAL PLANT COST SUMMARY

Case: CTCC - West."G"
Plant Size: 323.4 MW,net
Estimate Type: Conceptual
Cost Base (Jan) 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	HOT GAS CLEANUP & PIPING											
5.1	Gas Desulfurization(GE Moving Bed)											
5.2	Sulfur Recovery (Sulfuric Acid)											
5.3	Chloride Guard											
5.4	Particulate Removal											
5.5	Blowback Gas Systems											
5.6	Fuel Gas Piping											
5.9	HGCU Foundations											
	SUBTOTAL 5.											
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	37,873		2,684	188		$40,745	3,260		2,200	$46,205	143
6.2	Combustion Turbine Accessories	w/6.1		w/6.1								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations		134	156	11		$301	24		97	$422	1
	SUBTOTAL 6.	**$37,873**	**$134**	**$2,840**	**$199**		**$41,046**	**$3,284**		**$2,298**	**$46,628**	**144**
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	13,856		2,031	142		$16,030	1,282		866	$18,177	56
7.2	HRSG Accessories											
7.3	Ductwork		539	471	33		$1,043	83		225	$1,352	4
7.4	Stack	1,667		646	45		$2,358	189		382	$2,928	9
7.9	HRSG,Duct & Stack Foundations		83	84	6		$172	14		46	$232	1
	SUBTOTAL 7.	**$15,523**	**$621**	**$3,232**	**$226**		**$19,602**	**$1,568**		**$1,519**	**$22,690**	**70**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	9,545		1,605	112		$11,262	901		608	$12,771	39
8.2	Turbine Plant Auxiliaries	68		161	11		$241	19		39	$299	1
8.3	Condenser & Auxiliaries	1,759		497	35		$2,290	183		247	$2,720	8
8.4	Steam Piping	2,497		1,342	94		$3,933	315		637	$4,885	15
8.9	TG Foundations		132	420	29		$581	46		157	$784	2
	SUBTOTAL 8.	**$13,869**	**$132**	**$4,025**	**$282**		**$18,307**	**$1,465**		**$1,688**	**$21,460**	**66**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	2,359		534	37		$2,931	234		475	$3,641	11
9.2	Circulating Water Pumps	345		34	2		$381	30		41	$453	1
9.3	Circ.Water System Auxiliaries	42		6	0		$49	4		11	$63	0
9.4	Circ.Water Piping		818	938	66		$1,822	146		492	$2,460	8
9.5	Make-up Water System	94		143	10		$247	20		67	$334	1
9.6	Component Cooling Water Sys	91		82	6		$179	14		39	$232	1
9.9	Circ.Water System Foundations		607	1,090	76		$1,773	142		479	$2,394	7
	SUBTOTAL 9.	**$2,931**	**$1,426**	**$2,828**	**$198**		**$7,383**	**$591**		**$1,603**	**$9,576**	**30**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Slag Dewatering & Cooling											
10.2	Gasifier Ash Depressurization											
10.3	Cleanup Ash Depressurization											
10.4	High Temperature Ash Piping											
10.5	Other Ash Recovery Equipment											
10.6	Ash Storage Silos											
10.7	Ash Transport & Feed Equipment											
10.8	Misc. Ash Handling Equipment											
10.9	Ash/Spent Sorbent Foundation											
	SUBTOTAL 10.											

Client:	DEPARTMENT OF ENERGY		**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide			01:02 PM

TOTAL PLANT COST SUMMARY

Case:	CTCC - West."G"				
Plant Size:	323.4 MW,net	**Estimate Type:** Conceptual	**Cost Base (Jan)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,236		198	14		$1,448	116		156	$1,720	5
11.2	Station Service Equipment	1,583		132	9		$1,724	138		186	$2,048	6
11.3	Switchgear & Motor Control	1,262		212	15		$1,489	119		241	$1,849	6
11.4	Conduit & Cable Tray		761	2,414	169		$3,344	267		722	$4,333	13
11.5	Wire & Cable		817	825	58		$1,699	136		367	$2,202	7
11.6	Protective Equipment		85	287	20		$392	31		42	$466	1
11.7	Standby Equipment	221		5	0		$226	18		24	$269	1
11.8	Main Power Transformers	2,839		322	23		$3,183	255		344	$3,782	12
11.9	Electrical Foundations		137	383	27		$547	44		148	$738	2
	SUBTOTAL 11.	**$7,140**	**$1,800**	**$4,778**	**$334**		**$14,052**	**$1,124**		**$2,231**	**$17,407**	**54**
12	INSTRUMENTATION & CONTROL											
12.1	IGCC Control Equipment											
12.2	Combustion Turbine Control											
12.3	Steam Turbine Control											
12.4	Other Major Component Control	459		284	20		$763	61		124	$947	3
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	110		65	5		$180	14		29	$224	1
12.7	Computer & Accessories	4,392		130	9		$4,531	362		489	$5,383	17
12.8	Instrument Wiring & Tubing		1,371	4,307	301		$5,979	478		1,292	$7,749	24
12.9	Other I & C Equipment	808		363	25		$1,197	96		323	$1,616	5
	SUBTOTAL 12.	**$5,770**	**$1,371**	**$5,149**	**$360**		**$12,650**	**$1,012**		**$2,257**	**$15,919**	**49**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		28	567	40		$635	51		206	$892	3
13.2	Site Improvements		937	1,170	82		$2,188	175		709	$3,072	9
13.3	Site Facilities	1,678		1,665	117		$3,459	277		1,121	$4,857	15
	SUBTOTAL 13.	**$1,678**	**$965**	**$3,402**	**$238**		**$6,283**	**$503**		**$2,036**	**$8,821**	**27**
14	BUILDINGS & STRUCTURES											
14.1	Combustion Turbine Area		210	134	9		$353	28		76	$458	1
14.2	Steam Turbine Building		1,520	2,440	171		$4,131	331		892	$5,354	17
14.3	Administration Building		398	325	23		$746	60		161	$966	3
14.4	Circulation Water Pumphouse		78	47	3		$128	10		28	$166	1
14.5	Water Treatment Buildings		496	545	38		$1,079	86		233	$1,399	4
14.6	Machine Shop		204	157	11		$372	30		80	$481	1
14.7	Warehouse		329	239	17		$584	47		126	$757	2
14.8	Other Buildings & Structures		197	173	12		$382	31		82	$495	2
14.9	Waste Treating Building & Str.		440	948	66		$1,454	116		314	$1,884	6
	SUBTOTAL 14.		**$3,871**	**$5,008**	**$351**		**$9,230**	**$738**		**$1,994**	**$11,962**	**37**
	TOTAL COST	**$93,289**	**$13,500**	**$34,555**	**$2,419**		**$143,762**	**$11,501**		**$19,123**	**$174,386**	**539**

OPERATING LABOR REQUIREMENTS		
CTCC - West."G"		
Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift: Category	1 unit/mod.	Total Plant
Skilled Operator	1.0	1.0
Operator	2.0	2.0
Foreman	1.0	1.0
Lab Tech's, etc.	1.0	1.0
TOTAL-O.J.'s	5.0	5.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA			
CTCC - West."G"			
	Consumption		Unit
Item/Description	Initial	/Day	Cost
Water(/1000 gallons)		2,058	0.80
Chemicals*			
MU & WT Chem.(lbs)**	149,431	4,981	0.15
Limestone (ton)**			16.25
Z Sorb (lbs)**			7000.00
Nahcolite(ton)**			275.00
Other			
Supplemental Fuel(MBtu)**			
Gases,N2 etc.(/100scf)			1.50
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			
Slag(ton)			10.00
By-products & Emissions			
Sulfuric Acid(pounds)			75.00
Fuel(MMBtu)		52,992	2.76

CONTINGENCY FACTORS

CTCC - West."G"

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		
COAL & SORBENT PREP & FEED		
FEEDWATER & MISC. BOP SYSTEMS		21.3
GASIFIER & ACCESSORIES		
Gasifier & Auxiliaries(Destec)		
High Temperature Cooling		
ASU/Oxidant Compression		
Other Gasification Equipment		
HOT GAS CLEANUP & PIPING		
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator		5.0
Combustion Turbine Accessories		30.0
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		5.0
HRSG Accessories, Ductwork and Stack		16.9
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		14.2
COOLING WATER SYSTEM		20.1
ASH/SPENT SORBENT HANDLING SYS		
ACCESSORY ELECTRIC PLANT		14.7
INSTRUMENTATION & CONTROL		16.5
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS

CTCC - West."G"

Item/Description	Maintenance %
COAL & SORBENT HANDLING	
COAL & SORBENT PREP & FEED	
FEEDWATER & MISC. BOP SYSTEMS	1.9
GASIFIER & ACCESSORIES	
Gasifier & Auxiliaries(Destec)	
High Temperature Cooling	
ASU/Oxidant Compression	
Other Gasification Equipment	
HOT GAS CLEANUP & PIPING	
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	6.0
Combustion Turbine Accessories	0.5
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	2.0
HRSG Accessories, Ductwork and Stack	1.5
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries and Steam Piping	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.2
BUILDINGS & STRUCTURES	1.4

Pulverized Coal-Fired Supercritical Plant - 400 MWe

Economic and Financial Results

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY

TITLE/DEFINITION

Case:	SC Pulverized Coal		
Plant Size:	404.1 (MW,net)	HeatRate:	8,520 (Btu/kWh)
Primary/Secondary Fuel(type):	Illnois #6	Cost:	1.27 ($/MMBtu)
Design/Construction:	3 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	1999 (Jan.)	TPI Year:	2005 (Jan.)
Capacity Factor:	85 (%)		

CAPITAL INVESTMENT		**$x1000**	**$/kW**
Process Capital & Facilities		379,646	939.6
Engineering(incl.C.M.,H.O.& Fee)		30,372	75.2
Process Contingency			
Project Contingency		57,506	142.3
TOTAL PLANT COST(TPC)		$467,524	1157.1
TOTAL CASH EXPENDED	$467,524		
AFDC	$43,533		
TOTAL PLANT INVESTMENT(TPI)		$511,056	1264.8
Royalty Allowance			
Preproduction Costs		12,468	30.9
Inventory Capital		4,237	10.5
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		450	1.1
TOTAL CAPITAL REQUIREMENT(TCR)		$528,211	1307.3

OPERATING & MAINTENANCE COSTS (1999 Dollars)	**$x1000**	**$/kW-yr**
Operating Labor	3,871	9.6
Maintenance Labor	2,122	5.3
Maintenance Material	3,183	7.9
Administrative & Support Labor	1,498	3.7
TOTAL OPERATION & MAINTENANCE	$10,675	26.4
FIXED O & M		22.46 $/kW-yr
VARIABLE O & M		0.05 ¢/kWh

CONSUMABLE OPERATING COSTS,less Fuel (1999 Dollars)	**$x1000**	**¢/kWh**
Water	1,207	0.04
Chemicals	2,352	0.08
Other Consumables		
Waste Disposal	2,779	0.09
TOTAL CONSUMABLE OPERATING COSTS	$6,338	0.21
BY-PRODUCT CREDITS (1999 Dollars)		
FUEL COST (1999 Dollars)	$32,554	1.08

	1st Year (2005 $)		**Levelized (10th.Year $)**	
PRODUCTION COST SUMMARY		**¢/kWh**		**¢/kWh**
Fixed O & M	22.5/kW-yr	0.30	22.5/kW-yr	0.30
Variable O & M		0.05		0.05
Consumables		0.21		0.21
By-product Credit				
Fuel		1.00		0.93
TOTAL PRODUCTION COST		1.56		1.50
LEVELIZED CARRYING CHARGES(Capital)			197.4/kW-yr	2.65
LEVELIZED (10th.Year) BUSBAR COST OF POWER				4.15

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	SC Pulverized Coal			
Unit Size:/Plant Size:	404.1	MW,net	404.1	MWe
Location:	Middletown, USA			
Fuel: Primary/Secondary	Illnois #6			
Energy From Primary/Secondary Fuels	8,520	Btu/kWh		Btu/kWh
Levelized Capacity Factor / Preproduction(equivalent months):	85	%	1	months
Capital Cost Year Dollars (Reference Year Dollars):	1999	(January)		
Delivered Cost of Primary/Secondary Fuel	1.27	$/MBtu		$/MBtu
Design/Construction Period:	3	years		
Plant Startup Date (1st. Year Dollars):	2005	(January)		
Land Area/Unit Cost	300	acre	$1,500	/acre

FINANCIAL CRITERIA

Project Book Life:	20	years		
Book Salvage Value:		%		
Project Tax Life:	20	years		
Tax Depreciation Method:	Accel. based on ACRS Class			
Property Tax Rate:	1.0	% per year		
Insurance Tax Rate:	1.0	% per year		
Federal Income Tax Rate:	34.0	%		
State Income Tax Rate:	6.0	%		
Investment Tax Credit/% Eligible		%		%
Economic Basis:	10th.Year	Constant Dollars		

Capital Structure	% of Total	Cost(%)
Common Equity	20	16.5
Preferred Stock		
Debt	80	6.3
Weighted Cost of Capital:(after tax)	6.4 %	

Escalation Rates		Over Book Life		1999 to 2005	
	General		% per year		% per year
	Primary Fuel	-1.4	% per year	-1.34	% per year
	Secondary Fuel	0.7	% per year	1.07	% per year

Client:	DEPARTMENT OF ENERGY								**Report Date:**	23-Jul-99		
Project:	TASK 9-3 CCT Evaluation Guide									01:00 PM		

TOTAL PLANT COST SUMMARY

Case:	SC Pulverized Coal											
Plant Size:	404.1 MW,net		**Estimate Type:**	Conceptual				**Cost Base (Jan)**	1999	($x1000)		

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
1.1	Coal Receive & Unload	2,767		1,553	109		$4,429	354		957	$5,740	14
1.2	Coal Stackout & Reclaim	3,576		996	70		$4,642	371		1,003	$6,016	15
1.3	Coal Conveyors & Yd Crush	3,325		985	69		$4,379	350		946	$5,676	14
1.4	Other Coal Handling	870		228	16		$1,114	89		241	$1,444	4
1.5	Sorbent Receive & Unload	67		25	2		$94	7		20	$121	0
1.6	Sorbent Stackout & Reclaim											
1.7	Sorbent Conveyors	552		166	12		$730	58		158	$947	2
1.8	Other Sorbent Handling											
1.9	Coal & Sorbent Hnd.Foundations		3,363	4,790	335		$8,488	679		2,292	$11,459	28
	SUBTOTAL 1.	**$11,158**	**$3,363**	**$8,744**	**$612**		**$23,877**	**$1,910**		**$5,616**	**$31,402**	**78**
2	COAL & SORBENT PREP & FEED											
2.1	Coal Crushing & Drying	939		225	16		$1,179	94		255	$1,528	4
2.2	Coal Conveyor / Storage	5,556		1,490	104		$7,151	572		1,545	$9,267	23
2.3	Coal Injection System											
2.4	Misc.Coal Prep & Feed											
2.5	Sorbent Prep Equipment											
2.6	Sorbent Storage & Feed	214		724	51		$989	79		214	$1,281	3
2.7	Sorbent Injection System											
2.8	Booster Air Supply System											
2.9	Coal & Sorbent Feed Foundation											
	SUBTOTAL 2.	**$6,708**		**$2,439**	**$171**		**$9,318**	**$745**		**$2,013**	**$12,077**	**30**
3	FEEDWATER & MISC. BOP SYSTEMS											
3.1	FeedwaterSystem	4,545		1,473	103		$6,121	490		992	$7,603	19
3.2	Water Makeup & Pretreating	1,350		487	34		$1,871	150		404	$2,425	6
3.3	Other Feedwater Subsystems	3,496		1,267	89		$4,852	388		1,048	$6,288	16
3.4	Service Water Systems	259		161	11		$432	35		93	$560	1
3.5	Other Boiler Plant Systems	1,873		1,578	110		$3,562	285		962	$4,808	12
3.6	FO Supply Sys & Nat Gas	134		198	14		$345	28		75	$447	1
3.7	Waste Treatment Equipment	982		585	41		$1,607	129		347	$2,083	5
3.8	Misc. Power Plant Equipment	1,590		536	38		$2,163	173		701	$3,038	8
	SUBTOTAL 3.	**$14,228**		**$6,285**	**$440**		**$20,953**	**$1,676**		**$4,621**	**$27,250**	**67**
4	PC BOILER & ACCESSORIES											
4.1	PC Boiler	52,098		20,335	1,423		$73,857	5,909		3,988	$83,753	207
4.2	Open											
4.3	Open											
4.4	Interconnecting Pipe	w/4.1		w/4.1								
4.5	Primary Air System	w/4.1		w/4.1								
4.6	Secondary Air System	w/4.1		w/4.1								
4.8	Major Component Rigging		w/4.1	w/4.1								
4.9	PC Foundations		w/14.1	w/14.1								
	SUBTOTAL 4.	**$52,098**		**$20,335**	**$1,423**		**$73,857**	**$5,909**		**$3,988**	**$83,753**	**207**

Client:	DEPARTMENT OF ENERGY		**Report Date:**	23-Jul-99
Project:	TASK 9-3 CCT Evaluation Guide			01:00 PM

TOTAL PLANT COST SUMMARY

Case:	SC Pulverized Coal					
Plant Size:	404.1 MW,net	**Estimate Type:**	Conceptual	**Cost Base (Jan)**	1999	($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
5.1	Absorber Vessels & Accessories	19,060		4,526	317		$23,903	1,912		3,872	$29,687	73
5.2	Other FGD	1,488		1,860	130		$3,478	278		563	$4,319	11
5.3	ESP & Accessories	11,648		5,276	369		$17,294	1,383		1,868	$20,545	51
5.4	Other ESP	3,384		5,911	414		$9,708	777		1,049	$11,534	29
5.5	Gypsum Dewatering System	3,442		645	45		$4,133	331		669	$5,133	13
5.6	Open											
5.9	Open											
	SUBTOTAL 5.	**$39,022**		**$18,218**	**$1,275**		**$58,515**	**$4,681**		**$8,021**	**$71,217**	**176**
6	COMBUSTION TURBINE/ACCESSORIES											
6.1	Combustion Turbine Generator	N/A		N/A								
6.2	Combustion Turbine Accessories	N/A		N/A								
6.3	Compressed Air Piping											
6.9	Combustion Turbine Foundations											
	SUBTOTAL 6.											
7	HRSG, DUCTING & STACK											
7.1	Heat Recovery Steam Generator	N/A		N/A								
7.2	HRSG Accessories											
7.3	Ductwork	7,474		4,550	318		$12,343	987		2,666	$15,996	40
7.4	Stack	4,936		3,186	223		$8,345	668		1,352	$10,365	26
7.9	HRSG,Duct & Stack Foundations		277	355	25		$656	53		177	$886	2
	SUBTOTAL 7.	**$12,410**	**$277**	**$8,091**	**$566**		**$21,344**	**$1,708**		**$4,195**	**$27,247**	**67**
8	STEAM TURBINE GENERATOR											
8.1	Steam TG & Accessories	33,348		5,607	393		$39,348	3,148		2,125	$44,621	110
8.2	Turbine Plant Auxiliaries	187		441	31		$659	53		107	$818	2
8.3	Condenser & Auxiliaries	4,809		1,358	95		$6,262	501		676	$7,439	18
8.4	Steam Piping	6,827		3,671	257		$10,755	860		1,162	$12,777	32
8.9	TG Foundations		360	1,147	80		$1,588	127		429	$2,144	5
	SUBTOTAL 8.	**$45,171**	**$360**	**$12,225**	**$856**		**$58,612**	**$4,689**		**$4,498**	**$67,799**	**168**
9	COOLING WATER SYSTEM											
9.1	Cooling Towers	6,191		1,402	98		$7,691	615		1,246	$9,552	24
9.2	Circulating Water Pumps	905		89	6		$1,000	80		108	$1,188	3
9.3	Circ.Water System Auxiliaries	110		16	1		$128	10		28	$166	0
9.4	Circ.Water Piping		2,147	2,462	172		$4,781	382		1,291	$6,455	16
9.5	Make-up Water System	246		376	26		$649	52		175	$877	2
9.6	Component Cooling Water Sys	238		216	15		$469	38		101	$608	2
9.9	Circ.Water System Foundations		1,594	2,859	200		$4,653	372		1,256	$6,281	16
	SUBTOTAL 9.	**$7,691**	**$3,740**	**$7,420**	**$519**		**$19,370**	**$1,550**		**$4,205**	**$25,125**	**62**
10	ASH/SPENT SORBENT HANDLING SYS											
10.1	Ash Coolers	N/A		N/A								
10.2	Cyclone Ash Letdown	N/A		N/A								
10.3	HGCU Ash Letdown	N/A		N/A								
10.4	High Temperature Ash Piping	N/A		N/A								
10.5	Other Ash Recovery Equipment	N/A		N/A								
10.6	Ash Storage Silos	168		571	40		$779	62		126	$967	2
10.7	Ash Transport & Feed Equipment	5,687		10,246	717		$16,651	1,332		4,496	$22,478	56
10.8	Misc. Ash Handling Equipment											
10.9	Ash/Spent Sorbent Foundation		78	104	7		$189	15		51	$255	1
	SUBTOTAL 10.	**$5,855**	**$78**	**$10,920**	**$764**		**$17,618**	**$1,409**		**$4,673**	**$23,700**	**59**

Client: DEPARTMENT OF ENERGY | Report Date: 23-Jul-99 01:00 PM

Project: TASK 9-3 CCT Evaluation Guide

TOTAL PLANT COST SUMMARY

Case: SC Pulverized Coal

Plant Size: 404.1 MW,net | Estimate Type: Conceptual | Cost Base (Jan) 1999 ($x1000)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
11	ACCESSORY ELECTRIC PLANT											
11.1	Generator Equipment	1,433		230	16		$1,679	134		181	$1,994	5
11.2	Station Service Equipment	2,626		854	60		$3,540	283		382	$4,205	10
11.3	Switchgear & Motor Control	2,794		579	41		$3,413	273		553	$4,239	10
11.4	Conduit & Cable Tray		1,262	4,005	280		$5,548	444		1,198	$7,190	18
11.5	Wire & Cable		1,355	1,369	96		$2,819	226		609	$3,654	9
11.6	Protective Equipment	102		342	24		$468	37		51	$556	1
11.7	Standby Equipment	264		6	0		$270	22		29	$321	1
11.8	Main Power Transformers	2,575		121	8		$2,704	216		292	$3,213	8
11.9	Electrical Foundations		164	457	32		$652	52		176	$881	2
	SUBTOTAL 11.	**$9,793**	**$2,781**	**$7,963**	**$557**		**$21,094**	**$1,688**		**$3,472**	**$26,254**	**65**
12	INSTRUMENTATION & CONTROL											
12.1	PC Control Equipment	w/12.7		w/12.7								
12.2	Combustion Turbine Control	N/A		N/A								
12.3	Steam Turbine Control	w/8.1		w/8.1								
12.4	Other Major Component Control											
12.5	Signal Processing Equipment	W/12.7		w/12.7								
12.6	Control Boards,Panels & Racks	117		69	5		$191	15		31	$238	1
12.7	Computer & Accessories	4,667		138	10		$4,815	385		520	$5,720	14
12.8	Instrument Wiring & Tubing	1,457		4,577	320		$6,354	508		1,372	$8,235	20
12.9	Other I & C Equipment	859		386	27		$1,272	102		343	$1,717	4
	SUBTOTAL 12.	**$7,100**		**$5,170**	**$362**		**$12,632**	**$1,011**		**$2,267**	**$15,910**	**39**
13	IMPROVEMENTS TO SITE											
13.1	Site Preparation		32	640	45		$717	57		232	$1,007	2
13.2	Site Improvements		1,057	1,321	92		$2,470	198		800	$3,468	9
13.3	Site Facilities	1,895		1,879	132		$3,905	312		1,265	$5,483	14
	SUBTOTAL 13.	**$1,895**	**$1,089**	**$3,840**	**$269**		**$7,093**	**$567**		**$2,298**	**$9,958**	**25**
14	BUILDINGS & STRUCTURES											
14.1	Boiler Building		10,738	11,386	797		$22,922	1,834		4,951	$29,706	74
14.2	Turbine Building		3,226	5,179	363		$8,768	701		1,894	$11,363	28
14.3	Administration Building		326	416	29		$771	62		167	$1,000	2
14.4	Circulation Water Pumphouse		23	22	2		$47	4		10	$61	0
14.5	Water Treatment Buildings		227	226	16		$468	37		101	$607	2
14.6	Machine Shop		291	236	17		$543	43		117	$704	2
14.7	Warehouse		197	238	17		$452	36		98	$586	1
14.8	Other Buildings & Structures		121	124	9		$254	20		55	$329	1
14.9	Waste Treating Building & Str.		231	847	59		$1,137	91		246	$1,474	4
	SUBTOTAL 14.		**$15,382**	**$18,674**	**$1,307**		**$35,363**	**$2,829**		**$7,638**	**$45,830**	**113**
	TOTAL COST	**$213,129**	**$27,070**	**$130,325**	**$9,123**		**$379,646**	**$30,372**		**$57,506**	**$467,524**	**1157**

OPERATING LABOR REQUIREMENTS

SC Pulverized Coal

Operating Labor Rate(base):	26.15	$/hour
Operating Labor Burden:	30.00	% of base
Labor O-H Charge Rate:	25.00	% of labor

Operating Labor Requirements(O.J.)per Shift:

Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	8.0	8.0
Foreman	1.0	1.0
Lab Tech's, etc.	2.0	2.0
TOTAL-O.J.'s	13.0	13.0

CONSUMABLES, BY-PRODUCTS & FUELS DATA

SC Pulverized Coal

Item/Description	Consumption Initial	Consumption /Day	Unit Cost
Water(/1000 gallons)		4,864	0.80
Chemicals*			
MU & WT Chem.(lbs)**	353,173	11,772	0.15
Limestone (ton)**	10,822	360.7	16.25
Z Sorb (lbs)**			3.50
Nahcolite(ton)**			275.00
Other			
Supplemental Fuel(MBtu)**			
Gases,N2 etc.(/100scf)			
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)		453	12.00
Ash(ton)		352	10.00
By-products & Emissions			
Total By-products			
Fuel(ton)		3,541	29.63

CONTINGENCY FACTORS

SC Pulverized Coal

Item/Description	Contingency Factors(%) %Process	%Project
COAL & SORBENT HANDLING		21.8
COAL & SORBENT PREP & FEED		20.0
FEEDWATER & MISC. BOP SYSTEMS		20.4
PC BOILER & ACCESSORIES		
PC Boiler		5.0
Open		
Open		
Secondary Air System		
FLUE GAS CLEANUP		12.7
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator		
Combustion Turbine Accessories		
HRSG, DUCTING & STACK		
Heat Recovery Steam Generator		
HRSG Accessories, Ductwork and Stack		18.2
STEAM TURBINE GENERATOR		
Steam TG & Accessories		5.0
Turbine Plant Auxiliaries and Steam Piping		11.4
COOLING WATER SYSTEM		20.1
ASH/SPENT SORBENT HANDLING SYS		24.6
ACCESSORY ELECTRIC PLANT		15.2
INSTRUMENTATION & CONTROL		16.6
IMPROVEMENTS TO SITE		30.0
BUILDINGS & STRUCTURES		20.0

MAINTENANCE FACTORS SC Pulverized Coal	
Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.0
COAL & SORBENT PREP & FEED	3.9
FEEDWATER & MISC. BOP SYSTEMS	2.2
PC BOILER & ACCESSORIES	
PC Boiler	3.5
Open	
Open	
Secondary Air System	
FLUE GAS CLEANUP	3.7
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	
Combustion Turbine Accessories	
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	
HRSG Accessories, Ductwork and Stack	1.1
STEAM TURBINE GENERATOR	
Steam TG & Accessories	
Turbine Plant Auxiliaries and Steam Piping	4.0
COOLING WATER SYSTEM	1.2
ASH/SPENT SORBENT HANDLING SYS	3.0
ACCESSORY ELECTRIC PLANT	1.3
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	0.6
BUILDINGS & STRUCTURES	1.4

APPENDIX C

Range Estimating Program

RANGE ESTIMATING PROGRAM

OVERVIEW

Range estimating is a decision-making technology. It is a synergistic blend of Monte Carlo simulation, sensitivity analysis, heuristics, and proprietary algorithms for quantifying the uncertainties in estimating. The result is the determination of the probability of exceeding the targeted bottom line of a project and a prioritized ranking of all the project's critical elements according to their respective contributions to overall risk and opportunity.

During the seven-year period between 1968 and 1974, Decision Sciences Corporation worked with numerous corporations from a host of industries to develop a scientific and practical way for making decisions involving risk. From its original and extensive work in this area, Decision Sciences formulated and developed the technology called "Range Estimating," which was first reported in the technical literature in 1975. Since its introduction, this new technology has been expanded and improved upon by Decision Sciences and has been extremely effective in thousands of decisions involving risk, from the fairly small up to many multi-billion dollar projects. An integral part of this progress was Decision Sciences' development of a computer program incorporating all aspects of range estimating. It is called the "Range Estimating Program" (REP).

Predicting numerical values for future events is a way of life in most organizations. Nearly everyone is on the "estimating merry-go-round" forecasting and re-forecasting costs, profits, return on investment, and other performance criteria. All too often, however, the actual result differs significantly from the estimate. This difference is generally attributed to the vagaries of modern business, and rightly so. But this is simply an admission that conventional techniques of estimating are often incapable of coping with real world problems.

The reason for this deficiency is fundamental. With most conventional estimating methods, the forecast of each element in the estimate must ultimately be represented as a single number, even though management may know beforehand that thousands of other values are possible. If there are more than a few such elements, the number of possible ways in which they can combine and cascade to the bottom line defies conventional analysis.

The long-standing and repeated use of REP by hundreds of companies over the broadest of applications vividly demonstrates the soundness of range estimating as a decision-making technology and the effectiveness of REP in bringing that technology to the decision-maker in a very practical manner. REP provides information not available with conventional estimating methods. It is a powerful estimating tool that enables you to "look into the future" to determine the probability of achieving the bottom line target of your project. The following is a representative list of industries in which REP is being applied to solve varied types of problems:

- Chemical
- Construction
- Defense
- Education
- Electronics
- Engineering
- Entertainment
- Food
- Gambling
- Government
- Health
- Insurance
- Manufacturing
- Mining
- Oil and gas
- Paper products
- Pharmaceuticals
- Pipeline
- Resort
- Shoe
- Steel
- Textiles
- Transportation
- Utilities

The following is a partial list of problems to which REP is being applied:

- Conceptual cost estimating
- Detailed cost estimating
- Project management
- Engineering design
- Competitive bidding
- Research and development
- Mergers and acquisitions
- Capital expenditures
- Profit planning
- Budgetary control
- New product evaluation
- Advertising effectiveness

Given the range of possible occurrences for each critical item in your project, REP simulates its outcome 1,000 times to derive the following decision-oriented statistics:

- Degree of criticality of each major item in the project
- Entire spectrum of potential bottom line results
- Minimum potential bottom line
- Maximum potential bottom line
- Probability of achieving targeted bottom line
- Problems and opportunities ranked in order of importance
- Required contingency
- Answers to "what if" questions
- Other data vital to decision-making

CONCEPTS

Of necessity, the range estimating technology requires the introduction of new terms and, in some cases, new definitions of old ones. The primary purposes of this section are to introduce and explain the new terms and, where necessary, redefine old ones.

CATEGORY OF PROJECT ("PROFIT" OR "EXPENSE")

The primary performance measure of a project, its "bottom line," serves to categorize it either as a "profit" or "expense" type of project. If increasingly larger values of the bottom line are desirable from a management point of view, it is categorized as a "profit" type project. Examples of profit type projects are those whose bottom lines measure such items as total sales dollars, total gross profit dollars, net profit before taxes, net profit after taxes, return on investment, and earnings per share. Conversely, if increasingly larger values of the project's bottom line are undesirable from a management point of view, it is categorized as an "expense" type of project. Examples of expense type projects are those whose bottom lines measure such items as total cost of the project, total general and administrative expenses, man-hours, and total manufacturing costs.

CATEGORY OF ELEMENT ("PROFIT" OR "EXPENSE")

All elements in the project are categorized in a similar fashion. If increasingly larger values of the element are desirable, the element is categorized as a "profit" type of element. Examples of profit type elements are selling price per unit, market share, gross profit or margin per unit, and labor productivity. Conversely, if increasingly larger values of the element are undesirable, it is categorized as an "expense" type of element. Examples of expense type elements are manufacturing cost per unit, hourly labor rate, labor hours, takeoff quantity, purchased cost of material, equipment rental, and the cost of subcontracting an item.

CLASS OF ESTIMATE ("DETAILED" OR "CONCEPTUAL")

Each project is classified according to its type of estimate. If its estimate is the result of detailed studies of many or most of its major parts, it is classified as a "detailed" estimate. If its estimate was compiled in any other manner, it should be classified as a "conceptual" estimate.

CRITICAL VARIANCE OF THE BOTTOM LINE

The critical variance of the bottom line is defined as the maximum acceptable change from the targeted bottom line attributable to any one element of the project. Its relative value is determined by category of project, class of estimate, and empirical evidence gathered from many different types and sizes of projects to which range estimating has been applied over the years. These relative critical variances of the bottom line are given in the following table.

	Expense Project	Profit Project
Detailed Estimate:	0.2%	2.0%
Conceptual Estimate:	0.5%	5.0%

Thus, if the project is in the expense category, and its estimate is in the detailed class, the critical variance of its bottom line is 0.2 percent of its targeted bottom line. If its targeted bottom line is $10,000,000, then the critical variance of its bottom line is $20,000.

CRITICAL VARIANCE OF AN ELEMENT

The critical variance of an element is the amount the element must vary from its target estimate, while all other elements are held constant, to change the bottom line by an amount equal to the critical variance of the bottom line. The critical variance of an element is stated in the unit of measure of the element. Assume the critical variance of the bottom line is $20,000 as shown in the example above and that an element referred to as "Labor Rate" has a target estimate of $12.00 per hour and a critical variance of $0.34 per hour. This means that if the labor rate varies from its target estimate, either favorably or unfavorably, by an amount equal to 34 cents per hour, the result will be a $20,000 change in the project's bottom line.

CRITICAL ELEMENT

It is important to realize that an element's critical variance exists quite apart from the potential degree of performance of the element. That is, the element's critical variance may or may not represent a degree of departure from its target estimate, which is possible in the real world. It is this very quality of possibility or impossibility which determines whether the element is critical or noncritical. If it is possible that the actual performance of the element can vary from its target estimate, either favorably or unfavorably, by an amount greater than its critical variance, then that element is defined as a critical element. Conversely, if it is impossible for the actual performance of the element to vary, favorably or unfavorably, from its target estimate by an amount greater than its critical variance it is defined as a noncritical element.

PARETO'S LAW

Pareto's law states that, as a general rule, a relatively small number of elements in a population will collectively account for a very large percentage of the overall measure of the population. For example, a fairly small percentage of people account for a very large percentage of the total personal wealth. Similarly, a fairly small percentage of items in an inventory will collectively account for a very large part of the total dollar value of the inventory. This phenomenon is often referred to as the "80/20 rule," the implication being that a rather large portion (e.g., 80 percent) of the overall measure of the population can be attributed to a rather small portion (e.g., 20 percent) of its elements.

There is an abundance of real world examples of Pareto's law, and the area of project estimating is no exception. In fact, there are several different ways in which the Pareto effect manifests itself. The most obvious case is the fact that a relatively small number of elements in a project collectively account for a very large portion of its bottom line. Another example: a relatively small number of elements will create the majority of problems for management.

The example of paramount importance is simply this: a fairly small number of elements in a project will collectively account for the greatest portion of the total potential VARIABILITY of its bottom line. It is this bottom line variability, of course, which sets up the primary uncertainty in all project estimates. Note that, in this all important example of Pareto's law, those relatively few elements which account for the greatest portion of bottom line variability are, by the definition previously stated, "critical" elements. Thus, a very large percentage of the total uncertainty in a project is accounted for in the fairly small number of critical elements. In effect, this makes the problem manageable: relatively few items qualify as critical elements. Thus, relatively few require scrutiny and constant vigilance. All of the other project elements (the noncriticals) deserve no more attention than they normally receive: the future performance of each can adequately be assessed with the conventional single-point "best estimate."

THE RANGE

The manner in which we provide data depends upon the element's criticality. A range of possible values is assigned to each critical element of the project. The single-value estimate from the conventional estimate becomes the target estimate. In addition to the target estimate, the other components of the range are the lowest estimate, the highest estimate, and the probability factor.

The range is determined by specifying the lowest and highest values that the element can possibly assume. Since we are attempting to capture the reality of the future as we assess the range, the low and high should be relatively improbable numbers -- so improbable, in fact, that there is only a 1 percent chance that the actual value could materialize higher than the high and a 1 percent chance that the actual value could materialize lower than the low. The range must necessarily be broad to allow for all that might occur to the individual critical element.

When conventionally estimating the future outcome of a line item such as Labor Cost, for example, we are attempting to forecast the outcomes of all the factors that could possibly impinge upon the outcome of Labor Cost. We are, in essence, forecasting scope, productivity, labor rates, interest rates, weather, rework, material shortages, and other indefinable factors and their relationship to Labor Cost.

It is obviously not feasible to forecast each of these factors as we estimate Labor Cost. What is feasible is to consider these factors at their best case and worst case. For example, if all the factors that could impact Labor Cost were to collectively combine at their worst case, what would be their net effect on Labor Cost? In essence, what is called for is the most pessimistic assessment of Labor Cost, given the scenario painted by the worst case outcome of all the relevant factors. This highest estimate for Labor Cost would be a highly unlikely value because of the extremely low probability of all factors materializing at their worst case. Next, if we consider the outcome for Labor Cost, if all the relevant factors were to materialize at their best case, this optimistic scenario would produce the lowest estimate.

The span of possible values between these two boundaries defines the range for Labor Cost. Embedded within this range is the conventional single-point estimate -- the target estimate. This range reflects the degree of uncertainty about a given line item. If we knew very little about the item, the range would necessarily be broad to maintain a high degree of confidence that the actual value will materialize within the prescribed range. Conversely, if we knew everything about this one line item (no uncertainty), the range would be non-existent, and the conventional, single-point estimate would suffice.

The noncritical elements of the project can be handled in one of two ways. You may enter them as individual "frozen" elements or you may combine elements of like description into an "all other" category. For example, if there were a total of ten labor items in the conventional estimate, perhaps three of them would prove to be truly critical. The remaining seven items could be grouped as one element of the range estimate and called "All Other Labor Items." This single element is typically frozen, but if there is sufficient possible variation of the seven labor items as a group to change the bottom line by the critical variance, then this grouped element may become a critical element to be ranged.

Whatever resources are available to you in the determination of the conventional single-point estimate will also serve to provide the data required for Range Estimating. If the source of your data is a computerized historical database, that source can also provide the lowest and highest estimates as well as the probability factor. If the conventional, single-point estimate is a subjective assessment, based on experience, that experience can also serve to provide the lowest and highest estimates as well as the probability factor.

TARGET ESTIMATE - The target estimate is equivalent to the conventional single-value estimate of an element. The target estimate divides the range into two sections: favorable and unfavorable. If the element in question is a cost element, the value equal to or less than target is considered favorable. Any value greater than the target value of a cost element is considered unfavorable. Obviously, the reverse is true for a profit element.

LOWEST ESTIMATE - The lowest estimate is the most optimistic value you can imagine for a cost element (or the most pessimistic value you can imagine for a profit element), taking into account all foreseeable circumstances. It should represent a performance level below which the element is not reasonably expected to fall.

HIGHEST ESTIMATE - The highest estimate is the most pessimistic value you can imagine for a cost element (or the most optimistic value you can imagine for a profit element). It should represent a performance level above which the element is not reasonably expected to rise.

FROZEN ESTIMATE - Many elements of a project are not subject to sufficient uncertainty to be ranged. These noncritical elements of low uncertainty are best handled by a frozen estimate. There is no need to supply a lowest estimate, highest estimate, or probability factor for frozen elements. It is permissible to freeze an element at a value other than the target value. For instance, the portion of a project represented by a given element may be complete and the actual cost known. In this case, the frozen estimate would be the actual value and the target estimate would remain unchanged.

PROBABILITY FACTOR - The probability factor, expressed as a percent, is the probability that the actual value of an element will materialize between the lowest estimate and the target estimate. If the element is a cost element, the probability factor is your assessment of the chance of the actual value materializing in the favorable portion of the range -- at or below the target value. In the case of a profit element, it is your assessment of the chances that the actual value will materialize in the unfavorable portion of the range -- below the target value. It is an expression of the relative degree of optimism or pessimism about the target value. The probability factor must be expressed as a multiple of 5%.

The process of subjective determination of the probability factor is, in reality, a series of decisions that determines its value. The first decision is whether you are optimistic, pessimistic, or ambivalent about an element's expected performance. If the element is a cost element, for example, the choices are:

Pessimism	-	Probability factor 0 to 45
Ambivalence	-	Probability factor 50
Optimism	-	Probability factor 55 to 100

If you are pessimistic about the expected performance of the cost element, the next decision is the degree of pessimism.

Degree of Pessimism	Probability Factor
Absolute	0
Extreme	5 - 15
Moderate	20 - 30
Slight	35 - 45

APPENDIX D

Technology and Program Contacts

APPENDIX D
TECHNOLOGY AND PROGRAM CONTACTS

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